INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
www.idem.IN.gov

TO: Interested Parties / Applicant

DATE: May 1, 2008

RE: BP Products / 089-25484-00453

FROM: Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Notice of Decision: Approval - Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to IC 13-15-5-3, this permit is effective immediately, unless a petition for stay of effectiveness is filed and granted according to IC 13-15-6-3, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3 and IC 13-15-6-1 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204, **within eighteen (18) calendar days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

(1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location, date of this notice and all of the following:

(1) the name and address of the person making the request;
(2) the interest of the person making the request;
(3) identification of any persons represented by the person making the request;
(4) the reasons, with particularity, for the request;
(5) the issues, with particularity, proposed for considerations at any hearing; and
(6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178. Callers from within Indiana may call toll-free at 1-800-451-6027, ext. 3-0178.

Enclosures
FNPER.dot12/03/07

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Natalie Grimmer
BP Products North America Inc., Whiting Business Unit
2815 Indianapolis Blvd
Whiting, IN 46394

May 1, 2008

Re: 089-25484-00453
First Significant Source Modification to:
Part 70 permit No.: T089-6741-00453

Dear Ms. Grimmer:

BP Products North America Inc., Whiting Business Unit was issued Part 70 operating permit T089-6741-00453 on December 14, 2006 for a stationary refinery and marketing terminal. An application to modify the source was received on November 1, 2007. Pursuant to 326 IAC 2-7-10.5 **and 326 IAC 2-2,** the following emission units are approved for construction or modification at the source:

(1) One (1) redundant oil water separation system (identified as Tank 8a), with a maximum storage capacity of 124,800 gallons, equipped with a carbon canister for VOC control.

(2) 11PS H-200 furnace, to be modified by installing ultra low-NOx burners..

(3) No. 11A PS and No. 11C PS WARP, to shutdown the two existing blowdown stacks identified as stacks 11PS-A and 11PS-C, and to route the emergency pressure relief discharges that were previously routed to the blowdown stacks to the DDU flare, except for T-300 vacuum tower relief discharge and the COVs..

(4) New Coker (#2 Coker), which processes heavy crude fractions into coke, and new Coke Handling System. These facilities are identified as Unit 800 and are rated at 6,000 tons of coke per day. The New Coker (#2 Coker) heaters H-201, H-202, and H-203 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New Coker (#2 Coker) heater stacks have continuous emissions monitors (CEMS) for NOx and CO. The existing Coker and Coke Pile will be replaced as part of the CXHO Project. The facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(A) Process heaters comprising of:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted to	Emission Controls
H-201	208	800-01	Low-NO_X burners and selective catalytic reduction
H-202	208	800-02	Low-NO_X burners and selective catalytic reduction
H-203	208	800-03	Low-NO_X burners and selective catalytic reduction

(B) Storage and handling (including up to transfer points) of the bulk material comprised of a partially enclosed crusher, enclosed conveyors, enclosed storage, day bins, and rail car load out under the main operating scenario. In order to minimize fugitive emissions from the coke handling process, transfer points 1 and 10 will include enclosed conveyors and

transfer points 2 through 9 will use enclosed buildings, and water sprays. Coke handling operations will be expected to operate under this main operating scenario for at least 95% of operating hours annually. There will also be an alternative operating scenario which will consist of three enclosed conveyors with unenclosed transfer points. Coke handling operations are expected to operate under this alternate operating scenario for no more than 5% of operating hours annually.

(C) The Coker is connected to the South flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(5) One (1) storage tank, identified as TK-6255, with a maximum storage capacity of 14,028,000 gallons storing coker resid at a vapor pressure less than 0.5 psia. Tank TK-6255 is equipped with a fixed roof.

(6) The following process heaters at No. 12 Pipe Still, all of which are fired by natural gas, refinery gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-101A	355	130-05	Ultra low NOx Burners
H-101B	355	130-07	Ultra low NOx Burners
H-102	331	130-06	Ultra low NOx Burners

(7) Two (2) three-stage Claus sulfur recovery trains, identified as D and E trains.

(8) Two (2) Claus Offgas Treaters (COT), identified as COT1 and COT2, thermal oxidation systems which combust natural gas, each rated at 72 mmBTU/hr, exhausting at stacks S/V 162-06 and 162-07.

(9) Two (2) sulfur storage tanks, identified as SH-1 and SH-2, each with a maximum storage capacity of 1,008,000 gallons and used to store molten sulfur exhausting to stacks S/V 163-09 and 162-10. These tanks are both fixed roof tanks controlled by a caustic scrubber.

(10) Two (2) modular degassing units, to be installed as part of the CXHO project, which remove gases that are emitted during the cooling of molten sulfur. The gases will be vented to the front-end of Claus Trains D and/or E as part of the CXHO project.

(11) Two (2) sulfur pits (Sulfur Pits D and E), to be installed as part of the CXHO project, used to store molten sulfur and the vents routed to either COT 1 and/or COT 2.

(12) VRU 100/200 WARP, permitted in 2008, to shut down the existing VRU 100/200 blowdown stack, and route the pressure relief discharges that vented to the blowdown stack to the VRU flare.

(13) Vapor Recovery Unit VRU 400 for the New Coker (#2 Coker).

(14) The ISOM heater H-1, to be modified by replacing several burners with larger burners, with rated capacity remaining at 190 MMBTU/hr.

(15) The FCU 500 WARP, to shut down the existing FCU 500 blowdown stack and route the pressure relief discharges that vented to the blowdown stack to the VRU flare.

(16) The FCU 500 turnaround (TAR) project, for the repair or replacement of the power recovery turbine, and the air ring for the catalyst regenerator.

(17) The FCU 600 WARP, to shut down the existing FCU 600 blowdown stack and route the pressure relief discharges that vented to the blowdown stack to the FCU flare.

(18) The FCU 600 turnaround (TAR) project, for the repair or replacement of the main fractionator overhead condensers, the slurry and pump around system, unit pump replacement, FCU flare tip replacement, and additional controls to reduce plugging on the SCR.

(19) Five (5) direct-fired duct burners, rated at 41 mmBTU/hr each, equipped with low NOx burners and controlled by a Selective Catalytic Reduction (SCR) system.

(20) Hazardous Waste Treatment System:

Dewatering and thermal desorption system for processing sludge, including dissolved air flotation skimmimgs (DAF) and API oil/water separator sludge. The dewatering system will be equipped with a wet scrubber and carbon canister system and the thermal desorption unit will be equipped with a vapor recovery system to optimize absorption of hydrocarbons. The feed rate capacities at the dewatering system and thermal desorption systems are 22,500 tons of feed per year and 9,000 dry tons of solids per year, respectively. This facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of the permit:

(a) Two (2) centrifuges;

(b) Two (2) sludge surge tanks;

(c) One (1) oil/water mixture surge tank;
(d) One (1) enclosed auger transfer system;

(21) One (1) vapor recovery system on the thermal desorption unit including: an oil condensing/scrubbing system, a water condensing/scrubbing system, and an oil water separator. Uncondensed vapors from this system are routed to two (2) diesel fired burners for destruction of VOCs.

(22) Two (2) diesel fired burners rated at 4 mmBTU/hr each, for the thermal desorption system.

(23) One (1) storage tank (identified as Tank 5052) having a maximum storage capacity of 11,676,000 gallons. This tank will be used as a stormwater equalization tank and is equipped with an external floating roof.

(24) A brine treatment system with seven (7) wastewater tanks with vertical fixed roofs, identified as:

(A) TK-105A, with a storage capacity of 867,180 gallons;
(B) TK-105B, with a storage capacity of 867,180 gallons;
(C) TK-101, with a storage capacity of 66,096 gallons;
(D) TK-102, with a storage capacity of 66,096 gallons;
(E) TK-103, with a storage capacity of 66,096 gallons;
(F) TK-104A, with a storage capacity of 89,943 gallons; and
(G) TK-104B, with a storage capacity of 89,943 gallons.

(25) Cooling Towers:

Cooling Tower	Recirculation Rate/Make-up rate (gallons/minute)	Control Devices
Cooling Tower 7	21,000/451	high efficiency liquid drift eliminators
Cooling Tower 8	90,000/2956	high efficiency liquid drift eliminators

(26) Flares identified as follows:

Flare	Stack ID.	Dimensions	Process Units Normally Controlled by the Flare System *	Maximum Capacity (MMBtu/hr)	Pilot Fuel Type
GOHT Flare	802-03	H = 316 ft. D = 3.5 ft	GOHT	TBD	Fuel Gas and Natural Gas
South Flare	800-04	H = 350 ft. D = 5 ft	New Coker (#2 Coker), 12PS, Sulfur Recovery Complex	TBD	Fuel Gas and Natural Gas

(27) Replacement DHT Unit Heater B-601A, rated at 41.9 MMBtu per hour natural gas fired heater.

(28) The Gas Oil Hydrotreater (GOHT) Unit, identified as Unit ID 802 and rated at 120,000 barrels per day. The GOHT reduces the sulfur and nitrogen content of the FCU feed and improves the hydrogen content. Operation of the GOHT will enable the FCU to meet gasoline sulfur specifications and to improve FCU conversion yields. The GOHT Unit will be constructed as part of the CXHO Project and includes the following emission units:

(A) Process heaters comprising of:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-901A	47	802-01	Ultra low-NO_X burners
F-901B	47	802-02	Ultra low-NO_X burners

(B) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(C) The GOHT Unit vents to the GOHT Flare, used to control VOC emissions during emergency situations, unit startups and shutdowns.

(29) The New Hydrogen (New HU), identified as Unit ID 801, that produces 99+% pure hydrogen needed for the refinery hydrotreating processes. The New HU produces high purity hydrogen by reacting steam with methane. The New HU heaters HU-1 and HU-2 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New HU heater stacks have continuous emissions monitors (CEMs) for NOx and CO. The New HU includes the following sources of emissions and may also include insignificant activities listed in Section A.4 of this permit:

(A) Process heaters comprising:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted to	Emission Controls
HU-1	920*	801-01	Low-NO_X burners and selective catalytic reduction
HU-2	920*	801-02	Low-NO_X burners and selective catalytic reduction

(B) One cooling tower (HU Cooling Tower) rated at 14,000 gallons per minute recirculation rate controlled by high efficiency drift eliminators.

(C) The new Hydrogen Unit is connected to the HU Flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The HU Flare will be operated with a water seat or nitrogen purge. As such, there will be no purge gas emissions from the HU Flare. The HU Flare exhausts to S/V 801-03.

(D) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(30) Two (2) new boilers, identified as New Boiler 1 and New Boiler 2, each rated at 580 million BTU per hour, equipped with low-NOx burners and/or Selective Catalytic Reduction (SCR) for control of NOx, using either blended natural gas and refinery gas or only refinery fuel gas. A separate TRS CEMS shall be installed to measure the sulfur content of the fuel gas or fuel gas-natural gas blend fed to New Boiler 1 and New Boiler 2.

(31) The BOU heater F-401, to be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr..

(32) One storage tank (BT-002), will be modified. BP-002 was constructed in 1968, with a maximum storage capacity of 874,944 gallons, used to store petroleum hydrocarbons with a vapor pressure less than 15 psia, with a fixed roof and an internal floating roof.

(33) Three (3) emergency firepump engines, identified as Firepump 1, 2 and 3, each rated at 390 HP.

(34) One existing storage tank 3637, located in the Lake George Tank Field, will be reconstructed. This tank was originally constructed in 1956 as an external floating roof tank (mechanical shoe primary seal and a rim mounted secondary seal) with a capacity of 6,353,000 gallons.

(35) Installation of vapor control on gasoline loading at the Marine Dock Facility.

The following construction conditions are applicable to the proposed project:

General Construction Conditions

1. The data and information supplied with the application shall be considered part of this source modification approval. Prior to any proposed change in construction which may affect the potential to emit (PTE) of the proposed project, the change must be approved by the Office of Air Quality (OAQ).

2. This approval to construct does not relieve the permittee of the responsibility to comply with the provisions of the Indiana Environmental Management Law (IC 13-11 through 13-20; 13-22 through 13-25; and 13-30), the Air Pollution Control Law (IC 13-17) and the rules promulgated thereunder, as well as other applicable local, state, and federal requirements.

3. Effective Date of the Permit
Pursuant to IC 13-15-5-3, this approval becomes effective upon its issuance.

4. Pursuant to 326 IAC 2-1.1-9 and 326 IAC 2-7-10.5(i), the Commissioner may revoke this approval if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is suspended for a continuous period of one (1) year or more.

5. All requirements and conditions of this construction approval shall remain in effect unless modified in a manner consistent with procedures established pursuant to 326 IAC 2.

6. Pursuant to 326 IAC 2-7-10.5(l) the emission units constructed under this approval shall not be placed into operation prior to revision of the source's Part 70 Operating Permit to incorporate the required operation conditions.

This significant source modification authorizes construction of the new emission units. Operating conditions shall be incorporated into the Part 70 operating permit as a significant permit modification in accordance with 326 IAC 2-7-10.5(l)(2) and 326 IAC 2-7-12. Operation is not approved until the significant permit modification has been issued.

This decision is subject to the Indiana Administrative Orders and Procedures Act - IC 4-21.5-3-5.

If you have any questions on this matter, please contact Ma**tthew Stuckey** at the Indiana Department Environmental Management, Office of Air Quality, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 233-0**203** or toll free at 1-800-451-6027 extension 3-0**203**.

Original Signed By,

Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

MDM

cc: File - Lake County
Lake County Health Department
Northwest Regional Office
Air Compliance Section Inspector – Ramesh Tejuja
Compliance Data Section
Administrative and Development
Technical Support and Modeling - Michele Boner

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PART 70 SIGNIFICANT SOURCE MODIFICATION
OFFICE OF AIR QUALITY

BP Products North America Inc., Whiting Business Unit
2815 Indianapolis Blvd.
Whiting, Indiana 46394

herein known as the Permittee) is hereby authorized to construct subject to the conditions contained herein, the emission units described in Section A (Source Summary) of this Permit.

This approval is issued in accordance with 326 IAC 2-1-3 (SIP approved on 7/21/1997 (62 FR 38919), 326 IAC 2, and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17.

Significant Source Modification No. 089-25484-00453	
Original signed by: Matthew Stuckey, Branch Chief Permits Branch Office of Air Quality	Issuance Date: May 1, 2008

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D.2.13 Continuous Emissions Monitoring
D.2.14 PM and PM-10

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D.2.15 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.2.16 Record Keeping Requirements
D.2.17 Reporting Requirements

SECTION D.3 FACILITY OPERATION CONDITIONS – No. 12 Pipe Still

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.3.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.3.2 Particulate Matter

D.3.3 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.3.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.3.5 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.3.6 Equipment Leaks of VOC and Hazardous Air Pollutants (HAPs)[326 IAC 12] [326 IAC 8-4-8] [40 CFR 60, Subpart GGG] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.3.7 Volatile Organic Compounds (VOC) [326 IAC 8-4-2]
D.3.8 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ] [326 IAC 12]
D.3.9 Prevention of Significant Deterioration (PSD) Minoe Limit [326 IAC 2-2]

Compliance Determination Requirements
D.3.10 Operating Requirement
D.3.11 Continuous Emissions Monitoring
D.3.12 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]
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Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]
D.3.14 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]
D.3.15 Continuous Emissions Monitoring

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
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D.4.1 Particulate Matter [326 IAC 6.8-1-2]
D.4.2 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.4.3 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.4.4 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.4.5 New Source Performance Standards [326 IAC 12] [40 CFR 60, Subpart J]
D.4.6 Equipment Leaks of VOC [326 IAC 8-4-8]
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D.4.8 Requirements for 40 CFR Part 63, Subpart UUU

Compliance Determination Requirements
D.4.9 Operating Requirements
D.4.10 Testing Requirements [326 IAC 2-7-6(1), (6)] [326 IAC 2-1.1-11]
D.4.11 Operating Requirement

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]
D.4.12 Continuous Emissions Monitoring
D.4.13 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

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D.4.14 Record Keeping Requirements
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Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.5.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

D.5.2 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]
D.5.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

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D.5.4 Operating Requirement

Compliance Monitoring Requirements
D.5.5 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.5.6 Record Keeping Requirements
D.5.7 Reporting Requirements

SECTION D.6 FACILITY OPERATION CONDITIONS - Vapor Recovery Unit 300

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.6.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.6.2 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]
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D.6.4 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.6.5 Record Keeping Requirements
D.6.6 Reporting Requirements

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D.7.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGG] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.7.2 Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.7.3 Wastewater/Waste Streams [326 IAC 12] [40 CFR 60, Subpart QQQ]

Compliance Monitoring Requirements
D.7.4 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.7.5 Record Keeping Requirements
D.7.6 Reporting Requirements

SECTION D.8 FACILITY OPERATION CONDITIONS - Propylene Concentration Unit

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D.8.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Compliance Monitoring Requirements
D.8.2 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.8.3 Record Keeping Requirements
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D.9.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.9.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.9.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.9.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.9.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs)[326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.9.6 Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.9.7 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Compliance Determination Requirements
D.9.8 Operating Requirement
D.9.9 Operating Requirement

Compliance Monitoring Requirements
D.9.10 Continuous Emissions Monitoring
D.9.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.9.12 Record Keeping Requirements
D.9.13 Reporting Requirements

SECTION D.10 FACILITY OPERATION CONDITIONS - Aromatics Recovery Unit

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.10.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.10.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.10.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.10.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.10.5 Equipment Leaks of Volatile Organic Compounds and Hazardous Air Pollutants [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart J]
D.10.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Compliance Determination Requirements
D.10.7 Operating Requirement
D.10.8 Operating Requirement
D.10.9 Continuous Emissions Monitoring

Compliance Monitoring Requirements
D.10.10 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.10.11 Record Keeping Requirements
D.10.12 Reporting Requirements

SECTION D.11 FACILITY OPERATION CONDITIONS - Blending Oil Unit

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.11.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.11.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.11.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.11.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.11.5 Equipment Leaks of Volatile Organic Compounds (VOC) [326 IAC 8-4-8]
D.11.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

Compliance Determination Requirements
D.11.7 Operating Requirement
D.11.8 Operating Requirement
D.11.9 Continuous Emissions Monitoring

Compliance Monitoring Requirements
D.11.10 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.11.11 Record Keeping Requirements
D.11.12 Reporting Requirements

SECTION D.12 FACILITY OPERATION CONDITIONS - No. 2 Treatment Plant

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.12.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.12.2 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

Compliance Monitoring Requirements
D.12.3 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.12.4 Record Keeping Requirements
D.12.5 Reporting Requirements

SECTION D.13 FACILITY OPERATION CONDITIONS - No. 4 Treatment Plant

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.13.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.13.2 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

Compliance Monitoring Requirements
D.13.3 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.13.4 Record Keeping Requirements
D.13.5 Reporting Requirements

SECTION D.14 FACILITY OPERATION CONDITIONS - Butane, Propane, and Propylene Storage and Loading Facilities

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.14.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.14.2 General Conditions for Pressurized Storage Tanks

Compliance Monitoring Requirements
D.14.3 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.14.4 Record Keeping Requirements
D.14.5 Reporting Requirements

SECTION D.15 FACILITY OPERATION CONDITIONS - No. 3 Ultraformer Unit

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.15.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.15.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.15.3 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.15.4 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.15.5 Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.15.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]
D.15.7 Requirements for 40 CFR Part 63, Subpart UUU

Compliance Determination Requirements
D.15.9 Operating Requirement
D.15.10 Operating Requirement

Compliance Monitoring Requirements
D.15.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.15.12 Record Keeping Requirements
D.15.13 Reporting Requirements

SECTION D.16 FACILITY OPERATION CONDITIONS - No. 4 Ultraformer Unit

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.16.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.16.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.16.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.16.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.16.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs)[326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.16.6 Requirements for 40 CFR Part 63, Subpart UUU
D.16.7 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

Compliance Determination Requirements
D.16.8 Operating Requirement
D.16.9 Operating Requirement
D.16.10 Continuous Emissions Monitoring

Compliance Monitoring Requirements
D.16.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.16.12 Record Keeping Requirements
D.16.13 Reporting Requirements

SECTION D.17 FACILITY OPERATION CONDITIONS - Hydrogen Unit

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.17.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.17.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.17.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.17.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.17.5 Emission Offset and Prevention of Significant Deterioration [326 IAC 2-2] [326 IAC 2-3]
D.17.6 Equipment Leaks of VOC and Hazardous Air Pollutants (HAPs)[326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart, GGG] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.17.7 Wastewater Requirements [326 IAC 12] [40 CFR 60, Subpart QQQ]

Compliance Determination Requirements
D.17.8 Operating Requirement
D.17.9 Operating Requirement
D.17.10 Continuous Emissions Monitoring

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]
D.17.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.17.12 Record Keeping Requirements
D.17.13 Reporting Requirements

SECTION D.18 FACILITY OPERATION CONDITIONS - Distillate Desulfurizer Unit

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.18.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.18.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.18.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.18.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.18.5 Emission Offset and Prevention of Significant Deterioration (PSD) [326 IAC 2-2] [326 IAC 2-3]
D.18.6 Equipment Leaks of VOC and Hazardous Air Pollutants (HAPs)[326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart, GGG] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.18.7 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

Compliance Determination Requirements
D.18.8 Operating Requirement
D.18.9 Operating Requirement
D.18.10 Continuous Emissions Monitoring

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]
D.18.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.18.12 Record Keeping Requirements
D.18.13 Reporting Requirements

SECTION D.19 FACILITY OPERATION CONDITIONS - Cat Feed Hydrotreating Unit

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.19.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.19.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.19.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.19.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.19.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) 326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 12] [40 CFR 60, Subpart GGG]
D.19.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

Compliance Determination Requirements
D.19.7 Operating Requirement
D.19.8 Prevention of Significant Deterioration (PSD) [326 IAC 2-2]
D.19.9 Continuous Emissions Monitoring
D.19.10 Operating Requirement

Compliance Monitoring Requirements
D.19.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.19.12 Record Keeping Requirements
D.19.13 Reporting Requirements

SECTION D.20 FACILITY OPERATION CONDITIONS - Catalytic Refining Unit

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.20.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.20.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.20.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.20.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.20.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGG]
D.20.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]
D.20.7 Prevention of Significant Deterioration (PSD) [326 IAC 2-2]

Compliance Determination Requirements
D.20.8 Operating Requirement
D.20.9 Continuous Emissions Monitoring
D.20.10 Operating Requirement

Compliance Monitoring Requirements
D.20.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.20.12 Record Keeping Requirements

D.20.13 Reporting Requirements

SECTION D.21 FACILITY OPERATION CONDITIONS - Fluidized Catalytic Cracking Unit 500

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.21.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.21.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7-4.1-3]
D.21.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.21.4 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8]
D.21.5 Requirements for 40 CFR Part 63, Subpart UUU
D.21.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]
D.21.7 Alternative Opacity Requirements [326 IAC 5-1-3]

Compliance Determination Requirements
D.21.8 Operating Requirement
D.21.9 Continuous Emissions Monitoring

Compliance Monitoring Requirements
D.21.10 Inspection and Monitoring Requirements for the Electrostatic Precipitator [326 IAC 6.8-8-7]
D.21.11 Continuous Monitoring [326 IAC 3-5-1(e)] [326 IAC 6.8-8]
D.21.12 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.21.13 Record Keeping Requirements
D.21.14 Reporting Requirements

SECTION D.22 FACILITY OPERATION CONDITIONS - Fluidized Catalytic Cracking Unit 600

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.22.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-6]
D.22.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7-4.1-3]
D.22.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.22.4 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8]
D.22.5 Requirements for 40 CFR Part 63, Subpart UUU
D.22.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]
D.22.7 Operating Requirement
D.22.8 Alternative Opacity Requirements [326 IAC 5-1-3]
D.22.9 Continuous Emissions Monitoring

Compliance Monitoring Requirements
D.22.10 Inspection and Monitoring Requirements for the Electrostatic Precipitator [326 IAC 6.8-8-7]
D.22.11 Continuous Monitoring [326 IAC 3-5] [326 IAC 6.8-8]
D.22.12 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.22.13 Record Keeping Requirements
D.22.14 Reporting Requirements

SECTION D.23 FACILITY OPERATION CONDITIONS - No. 1 Stanolind Power Station

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.23.1 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.23.2 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.23.3 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.23.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.23.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8]
D.23.6 Nitrogen Oxides Budget Trading Program [326 IAC 10-4]
D.23.7 Wastewater/Waste Streams [40 CFR 60, Subpart QQQ] [326 IAC 12]

Compliance Determination Requirements

D.23.8 Operating Requirement

Compliance Monitoring Requirements

D.23.9 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.23.10 Record Keeping Requirements
D.23.11 Reporting Requirements

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D.24.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.24.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]
D.24.3 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.24.4 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.24.5 Fuel Gas Hydrogen Sulfide (H2S) [40 CFR 60, Subpart J]
D.24.6 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8]
D.24.7 Nitrogen Oxides Budget Trading Program [326 IAC 10-4]
D.24.8 Wastewater/Waste Streams [326 IAC 12] [40 CFR 60, Subpart QQQ]

Compliance Determination Requirements

D.24.9 Operating Requirement
D.24.10 Continuous Emissions Monitoring

Compliance Monitoring Requirements

D.24.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

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D.24.12 Record Keeping Requirements
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D.25.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-1-6]
D.25.2 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

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D.25.3 Petroleum Refineries [326 IAC 8-4-2]
D.25.4 D.25.4 Wastewater / Waste Streams [326 IAC 20 16 1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]
D.25.5 Wastewater/Waste Streams [40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF]
D.25.6 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20 16 1] [40 CFR 63, Subpart CC] [326 IAC 8 4 8] [326 IAC 12] [40 CFR 60, Subpart GGGa]

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]
D.25.7 Fuel Gas Hydrogen Sulfide (H2S)[40 CFR 60, Subpart J]
D.25.8 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.25.9 Record Keeping Requirements
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D.26.1 Petroleum Refineries [326 IAC 8-4-2]
D.26.2 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]
D.26.3 Volatile Organic Compound (VOC) Emission Offset

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D.26.4 Record Keeping Requirements
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D.27.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) and Benzene [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 14] [40 CFR 61, Subpart J]
D.27.2 Petroleum Liquid Storage Facilities [326 IAC 8-4-3]
D.27.3 Volatile Organic Liquid Storage Vessels [326 IAC 8-9]
D.27.4 VOC and HAP Emissions From Storage Vessels [326 IAC 12] [40 CFR 60, Subpart K] [40 CFR 60, Subpart Ka] [40 CFR 60, Subpart Kb] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
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D.27.6 Petroleum Refineries - Separators [326 IAC 8-4-2]
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D.27.8 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]
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D.28.2 New Source Performance Standards [326 IAC 12] [40 CFR 60, Subpart J]
D.28.3 VOC Emissions [326 IAC 8-7]
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Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.28.5 Record Keeping Requirements
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D.29.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

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D.29.2 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

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D.30.1 National Emission Standards for HAPs from Petroleum Refineries and Standards of Performance for Bulk Gasoline Terminals [40 CFR 63, Subpart CC] [326 IAC 20-16] [40 CFR 60, Subpart XX] [326 IAC 12-1]
D.30.2 Bulk Gasoline Terminals [326 IAC 8-4-4]
D.30.3 Leaks from Transports and Vapor Collection Systems [326 IAC 8-4-9]
D.30.4 Particulate Matter Limitation (PM) [326 IAC 6.8-1-2(b)(3)]

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D.30.5 Record Keeping Requirements
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Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.31.1 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.31.2 Operating Requirements

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]
D.31.3 Compliance Monitoring Requirements [326 IAC 2-3]

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Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.32.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]
D.32.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7- 4.1-3]
D.32.3 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]
D.32.4 NSPS Requirements [326 IAC 12-1] [40 CFR 60, Subpart UU]
D.32.5 Particulate Matter [326 IAC 6.8-1-2]
D.32.6 NESHAP Requirements [40 CFR Part 63, Subpart CC] [326 IAC 20-16]
D.32.7 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [40 CFR 60, Subpart GGG]
D.32.8 Natural Gas Usage Limit [326 IAC 2-2] [326 IAC 2-3]
D.32.9 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

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D.32.10 Operating Requirement
D.32.11 Operating Requirement
D.32.12 Opacity Control

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D.34.2 Emission Offset Minor Limit [326 IAC 2-3]
D.34.3 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]
D.34.4 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) and Benzene [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8]
D.34.5 Standards for Marine Tank Loading [326 IAC 20-17] [40 CFR 63, Subpart Y] [40 CFR 63, Subpart CC]
D.34.6 Petroleum Liquid Storage Facilities [326 IAC 8-4-3]
D.34.7 VOC and HAP Emissions From Storage Vessels [326 IAC 12] [40 CFR 60, Subpart Kb] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

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D.34.8 Operating Requirement
D.34.9 Testing Requirements
D.34.10 Operating Requirement

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D.35.2 Standards for Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.35.3 Equipment Leaks of Benzene [326 IAC 14] [40 CFR 61, Subpart J]
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D.36.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]
D.36.2 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

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Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
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D.37.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7-4.1-1]
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D.37.5 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]
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Compliance Determination Requirements
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D.42.2 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
D.42.3 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8 4 8] [326 IAC 20 16 1] [40 CFR 63, Subpart CC] [40 CFR 60, Subpart VV](40 CFR 60, Subpart GGGa)
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D.42.5 Operating Requirement
D.42.6 Continuous Emissions Monitoring

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D.44.4 Fuel Gas Hydrogen Sulfide (H2S) [326 IAC 12][40 CFR 60, Subpart J]
D.44.5 Equipment Leaks of Volatile Prganic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 8-4-8][40 CFR 60, Subpart GGGa]
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D.45.2 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits
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[RESERVED]

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Section E.25 Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006 - 40 CFR 60, Subpart GGGa

E.25.1 General Provisions Relating to NSPS Subpart GGGa [40 CFR Part 60, Subpart A]
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Section E.26 Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 - 60 CFR 60, Subpart VVa

E.26.1 General Provisions Relating to NSPS Subpart VVa [40 CFR Part 60, Subpart A]
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PART 70 FORMS

Certification
Emergency Occurrence Report
Quarterly Deviation and Compliance Monitoring Report
Part 70 Quarterly Reports
Appendix A - Fugitive Dust Control Plan

SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) and Hammond Department of Environmental Management. The information describing the source contained in conditions A.1 through A.3 and A.4 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)] [326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary refinery and marketing terminal.

Source Address:	2815 Indianapolis Blvd, Whiting, Indiana 46394-0170
Mailing Address:	P.O. Box 710, Whiting, Indiana 463940-170
General Source Phone Number:	219-473-3179
SIC Code:	2911
County Location:	Lake
Source Location Status:	Nonattainment for PM2.5 and 8-hour ozone standard Attainment for all other criteria pollutants
Source Status:	Part 70 Permit Program Major Source, under PSD and Emission Offset Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

A.2 Part 70 Source Definition [326 IAC 2-7-1(22)]

This stationary source consists of two (2) plants, with a third plant located on an adjacent site:

(a) The Whiting Refinery (previously designated 089-00003), located at 2815 Indianapolis Boulevard, Whiting, Indiana 46394; and

(b) The Marketing Terminal (previously designated 089-00004), located at 2530 Indianapolis Boulevard, Whiting, Indiana 46394.

(c) INEOS USA LLC (designated as 089-00076), 2357 Standard Avenue, Whiting, IN 46394.

Since the two (2) plants (Whiting Refinery and the Marketing Terminal) are located on contiguous or adjacent properties, the plants are under common control of the same entity, and the Whiting Refinery supports the Marketing Terminal, the two (2) plants are considered one (1) source.

In the case of the BP Whiting refinery and the INEOS USA LLC chemical plant, neither plant has a major role in the day-to-day operations of the other plant. There is no contract between the two companies concerning the acceptance or usage of raw materials. Each plant is free to obtain raw materials from other sources. The chemical plant has obtained raw materials from other sources in the past when the refinery has been unable to supply it. Neither plant provides a majority of its output to the other plant. Neither plant has the right to assume control of the other under any circumstance. The INEOS chemical plant purchases steam, water, wastewater service and a raw material stream from the BP refinery. If the refinery were to cease operations, the chemical plant could continue to operate.

The BP refinery purchases a hydrocarbon stream from the chemical plant. It also sends by-products to the INEOS chemical plant's flare. The flared by-products come from the venting of rail cars and the depressurizing of drums. The refinery does not rely on the hydrocarbon stream in order to produce its principal products. The refinery does not rely on the INEOS flare. If the INEOS chemical plant were to cease operations, the refinery could continue to operate. The refinery has

a procedure in place on what steps its employees take when the INEOS flare is unavailable. Neither plant is dependent on the other to operate.

Since there is no common control, the refinery and the chemical plant are not part of the same major source. There is no need to examine the other two criteria under the definition of major source. Therefore, the chemical plant is not included in this Title V Operating Permit. The chemical plant will receive a separate operating permit.

A.3 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(15)]

This stationary source consists of the following emission units and pollution control devices:

(a) Nos. 11A and 11C Pipe Stills built in 1956, with a rated capacity of 220,800 barrels per day, and identified as Unit ID 120 process crude into various hydrocarbon fractions based on boiling points. This facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) The following process heaters, all of which are fired by natural gas, refinery gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-1X	250	120-01	None
H-2	45	120-02	None
H-3	55	120-03	None
H-200	249.5	120-05	Current: None After CXHO: Low NOx Burners
H-300	180	120-06	None

(2) Two (2) vacuum hot wells (D-21, constructed in 1990 and D-26, constructed in 1997) and one (1) sump (D-20, constructed in 1990), with D-20, D-21, and D-26 each venting to S/V 120-07, at No. 11 A Pipe Still.

(3) One (1) vacuum hot well (D-300), constructed in 1995 venting to S/V 120-08 at No. 11C Pipe Still.

The vacuum tower overhead system consists of a series of condensers, steam ejectors, and vacuum pumps. The majority of the overhead vapors are condensed and drained to the hotwell, which is pumped back to the front end of the unit for reprocessing. The gas compressors pull the remaining vapor that is not condensed in the overhead system into the wet gas system, where the hydrocarbon is reprocessed by down stream units. A thermocouple system (with temperature alarm) is used to monitor the vacuum on the system.

(4) Leaks from equipment in the process, including pumps; compressors (K4 and K4A at No. 11A Pipe Still and K300A and K300-B at the No. 11C Pipe Still); pressure relief devices; sampling connection systems; open-ended lines or valves; and instrumentation systems.

(5) One (1) storage tank (identified as Tank 3030) with a maximum storage capacity of 847,000 gallons. This tank was installed in 1957 and is equipped with an external floating roof.

(6) One (1) oil water separation system (identified as Tank 8) with a maximum storage capacity of 124,800 gallons.

(7) One (1) redundant oil water separation system (identified as Tank 8a), permitted in 2008, with a maximum storage capacity of 124,800 gallons, equipped with a carbon canister for VOC control.

(8) As part of the No. 11A PS and No. 11C PS WARP, per SPM 089-25488-00453, the two existing blowdown stacks identified as stacks 11PS-A and 11PS-C will be shutdown, with the emergency pressure relief discharge that was previously routed to the blowdown stacks will be re-routed to the DDU flare, except for T-300 vacuum tower relief discharge and the COVs.

(b) No. 11B Coker, which processes heavy crude fractions into coke, and Coke Pile. These facilities are identified as Unit 120 and are rated at 2,000 tons of coke per day. The facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) Four (4) process heaters comprising:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-101 H-102 H-103 H-104	200 (total)	120-04	None

(2) Storage and handling of the bulk material. Fugitive emissions are controlled by keeping the coke wetted and having a 15' sheet piling wall surrounding the coke pile. The coke pile height will not exceed 15'.

(3) The No. 11B Coker is connected to the DDU flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges and other connectors.

(Note: The No. 11B Coker and Coke Handling System, heaters H-101, H-102, H-103, and H-104 will be replaced by the New Coker (#2 Coker) and Coke Pile and heaters H-201, H-202, and H-203 as part of the CXHO project, identified later in this section).

New Coker (#2 Coker), constructed as part of CXHO project, which processes heavy crude fractions into coke, and new Coke Handling System. These facilities are identified as Unit 800 and are rated at 6,000 tons of coke per day. The New Coker (#2 Coker) heaters H-201, H-202, and H-203 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New Coker (#2 Coker) heater stacks have continuous emissions monitors (CEMS) for NOx and CO. The existing Coker and Coke Pile will be replaced as part of the CXHO Project. The facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) Process heaters comprising of:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted to	Emission Controls
H-201	208	800-01	Low-NO_X burners and selective catalytic reduction
H-202	208	800-02	Low-NO_X burners and selective catalytic reduction
H-203	208	800-03	Low-NO_X burners and selective catalytic reduction

(2) Storage and handling (including up to 10 transfer points) of the bulk material comprised of a partially enclosed crusher, enclosed conveyors, enclosed storage, day bins, and rail car load out under the main operating scenario. In order to minimize fugitive emissions from the coke handling process, transfer points 1 and 10 will include enclosed conveyors and transfer points 2 through 9 will use enclosed buildings, and water sprays. Coke handling operations will be expected to operate under this main operating scenario for at least 95% of operating hours annually. There will also be an alternative operating scenario which will consist of three enclosed conveyors with unenclosed transfer points. Coke handling operations are expected to operate under this alternate operating scenario for no more than 5% of operating hours annually.

(3) The Coker is connected to the South flare system (included in Section D.35). The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) One (1) storage tank, identified as TK-6255, with a maximum storage capacity of 14,028,000 gallons storing coker resid at a vapor pressure less than 0.5 psia. Tank TK-6255 is equipped with a fixed roof.

(5) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the CXHO Project, which processes crude into various hydrocarbon fractions based on boiling points, identified as Unit ID 130, and is rated at 336,000 barrels per day. Heaters identified as H-1AN, H-1AS, H-1B, H-2, H-1CN, and H-1CX will be shutdown and replaced by heaters H-101A, H-101B, and H-102 as part of the CXHO project. The facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) The following process heaters, all of which are fired by natural gas, refinery gas, or liquified petroleum gas:

Heater Identification	Construction Date/Permitted Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-1AN	1959	121.5	130-01	None
H-1AS	1959	121.5	130-01	None
H-1B	1959	243	130-01	None
H-2	1959	174	130-01	Ultra low NO_x burners

Heater Identification	Construction Date/Permitted Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-1CN	1995	120	130-02	Low NO_x burners
H-1CX	1977	410	130-04	Low NO_x burners
H-101A	Permitted in 2008 (SPM 089-25488-00453)	355	130-05	Ultra low NOx Burners
H-101B	Permitted in 2008 (SPM 089-25488-00453)	355	130-07	Ultra low NOx Burners
H-102	Permitted in 2008 (SPM 089-25488-00453)	331	130-06	Ultra low NOx Burners

[a] No longer in service -- was rated at 120 MMBtu/hour.
[b] No longer in service -- was exhausted to stack 130-03.

(2) One (1) vacuum hot well, identified as D-7, constructed in 1995, and venting to S/V 130-05. The vacuum tower overhead system consists of a series of condensers, steam ejectors, and vacuum pumps. The majority of the overhead vapors are condensed and drained to the hotwell, which is pumped back to the front end of the unit for reprocessing. The gas compressors pull the remaining vapor that is not condensed in the overhead system into the wet gas system, where the hydrocarbon is reprocessed by down stream units. A thermocouple system (with temperature alarm) is used to monitor the vacuum on the system.

(3) Leaks from process equipment.

(d) The Sulfur Recovery Unit (SRU) Facility, identified as Unit ID 162, originally constructed in 1971 and expanded in 1981 and 1995, and rated at 600 long tons per day, to be modified as part of the CXHO Project, increasing the capacity to 1,300 long tons per day of sulfur. The facility includes the following and may also include insignificant activities listed in Section A.4 of this permit:

(1) Three (3) three-stage Claus sulfur recovery trains, identified as A, B, and C, and two (2) additional three-stage Claus sulfur recovery trains installed after modification, identified as D and E trains.

(2) One (1) Beavon-Stretford tail gas unit (B/S TGU), a reduction system with a burner capacity of 24.3 MMBtu per hour, exhausting at stack S/V 162-02. The B/S TGU will be decommissioned as part of the CXHO project.

(3) One (1) tail gas unit (SBS TGU), an oxidation system with a burner capacity of 40 MMBtu per hour, exhausting at stack 162-04. The SBS TGU will be decommissioned as part of the CXHO project.

(4) One (1) caustic soda scrubbing tower to control sulfur dioxide emissions from the SBS TGU. The caustic soda scrubbing tower will be decommissioned as part of the CXHO project.

(5) One (1) cooling tower, identified as the SBS cooling tower, used to remove sodium bisulfite from the caustic scrubbing tower exhaust stream, equipped with a high-efficiency mist eliminator, and exhausting at stack 162-05. The SBS cooling tower will be decommissioned as part of the CXHO project.

(6) Gas quenching and cooling towers other than the SBS cooling tower, to be decommissioned as part of the CXHO project.

(7) One (1) quench separator with mist eliminators, to be decommissioned as part of the CXHO project.

(8) One (1) gas cooler and water condenser with sulfur dioxide stripper, to be decommissioned as part of the CXHO project.

(9) Caustic soda storage tanks and sodium bisulfite storage tanks, and handling equipment, to be decommissioned as part of the CXHO project.

(10) One (1) standby incinerator, used only in the event of an emergency, having stack ID S/V 162-01. The standby incinerator will be decommissioned as part of the CXHO project.

(11) One (1) flare, exhausting to stack S/V 162-03 which controls H_2S and VOC emissions during emergency situations, unit start-ups/shut-downs, and preparation of equipment for maintenance. Refinery or natural gas is used as a constant purge stream. Pilot gas is natural gas.

(12) One (1) modular degassing unit, which removes gases that are emitted during the cooling of molten sulfur. Removed gases are vented to the SBS TGU. Removed gases will be vented to the front-end of Claus Trains D and/or E as part of the CXHO project.

(13) Two (2) modular degassing units, to be installed as part of the CXHO project, which remove gases that are emitted during the cooling of molten sulfur. The gases will be vented to the front-end of Claus Trains D and/or E as part of the CXHO project.

(14) Three (3) sulfur pits, (Sulfur Pits A, B, and C) used to store molten sulfur with their vent stacks routed to the B/S TGU and/or the SBS. As part of the CXHO project, the vents from the sulfur pits A, B and C will be routed to either COT 1 and/or COT 2.

(15) Two (2) sulfur pits (Sulfur Pits D and E), to be installed as part of the CXHO project, used to store molten sulfur and the vents routed to either COT 1 and/or COT 2.

(16) One (1) sour water storage tank, identified as TK-431, having a maximum storage capacity of 845,600 gallons and equipped with an external floating roof. The maximum true vapor pressure of the material stored in this tank is less than 0.5 psia.

(17) One (1) sour water storage tank, identified as TK-410, permitted in 2006, having a maximum storage capacity of 4,351,200 gallons and equipped with an external floating roof. The maximum true vapor pressure of the material stored in this tank is less than 0.5 psia.

(18) Two (2) Claus Offgas Treaters (COT), identified as COT1 and COT2, to be installed as part of the CXHO project, thermal oxidation systems which combust natural gas, each rated at 72 mmBTU/hr, exhausting at stacks S/V 162-06 and 162-07.

(19) Two (2) sulfur storage tanks, identified as SH-1 and SH-2, each with a maximum storage capacity of 1,008,000 gallons and used to store molten sulfur exhausting to stacks S/V 163-09 and 162-10. These tanks will be constructed as part of the CXHO Project and are both fixed roof tanks controlled by a caustic scrubber.

Main Operating Scenario Pre-CXHO:
Approximately 80% of tail gases from the three trains are sent to the B/S TGU, with the remainder sent to the SBS TGU.
Alternate Operating Scenario #1 Pre-CXHO:
One train and the B/S TGU are not operated. Tail gases from the other two trains are sent to the SBS TGU.
Alternate Operating Scenario #2 Pre-CXHO:
The B/S TGU is not operated. Tail gases from the three trains are sent to the SBS TGU.
Alternate Operating Scenario #3 Pre-CXHO:
The SBS TGU is not operated. Tailgases from the three trains are sent to the B/S TGU.
Main Operating Scenario Post-CXHO:

The tail gases from the five trains are sent to both of the COTs.

Alternate Operating Scenario #1 Post-CXHO:

One of the COTs is not operated and the tail gases from the five trains are sent to the other COT.

(e) (1) Vapor Recovery Unit 100 (VRU-100) identified as Unit ID 241, and Vapor Recovery Unit 200 (VRU-200) identified as Unit ID 231, permitted for turnaround (TAR) in 2008 to repair or replace tower trays and increase existing pumping and cooling capacities. Gasoline and lighter products from the FCUs are separated in the VRUs using a series of distillation towers. The VRUs are connected to flare stack S/V 241-01, the VRU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes leaks from process equipment including one (1) compressor (identified as J-3E located at VRU-100), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system. The facility may also include insignificant activities listed in Section A.4 of this permit.

(2) VRU 100/200 WARP, permitted in 2008, to replace the existing VRU 100/200 blowdown stack, with the exhaust being re-routed to the VRU flare.

(f) (A) The Vapor Recovery Unit 300 (VRU 300), identified as Unit ID 150. Light ends and naphtha are separated in the VRU using a series of distillation towers. This unit is connected to flare stack S/V 241-01, the VRU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) off-gas knock out drum (D-400) which exhausts to flare stack S/V 241-01.

(2) Leaks from process equipment, including two (2) compressors (identified as K-340 and K-351), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation system.

(B) Vapor Recovery Unit VRU 400 for the New Coker (#2 Coker), permitted in 2008, to be installed as part of the CXHO Project.

(g) The Alkylation Unit, identified as Unit ID 140, combines isobutane with butylenes and propylenes to produce alkylate. The alkylate, a high octane naphtha, is blended into gasoline. This unit was built in 1961 and expanded in 1989. This unit is connected to flare stack S/V 140-01, the Alky Flare, to control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) off gas knock-out drum (D-22), which exhausts to flare stacks S/V 140-01.

(2) One (1) spent acid stripper drum (D-13), which exhausts to flare stacks S/V 140-01.

(3) One (1) spent caustic drum (D-32), which exhausts to flare stacks S/V 140-01.

(4) Leaks from process equipment, including two (2) compressors (identified as K-1 and K-1A), valves, pumps, pressure relief devices, sampling connection systems, and instrumentation system.

(h) The Propylene Concentration Unit (PCU), identified as Unit ID 145, purifies propylene for sale to chemical plants and eventual manufacture into polypropylene plastic. This unit also has a treating system, which purifies propane. This unit is connected to flare stack S/V 140-01 (the Alky Flare). The flare controls VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes a caustic degassing drum (D-100) that is vented to flare stack S/V 140-01 and leaks from process equipment, including one compressor (identified as k-104), pumps, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation system. This facility may include insignificant activities listed in Section A.4 of this permit.

(i) The Isomerization Unit (ISOM), identified as Unit ID 210, was constructed in 1985 as a conversion of the No.2 Ultraformer. The Isomerization process converts low octane naphtha into high octane gasoline blending components. This unit is connected to flare stack S/V 220-04, the UIU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the CXHO project, the ISOM heater H-1 will be modified by replacing several burners with larger burners, with rated capacity remaining at 190 MMBTU/hr. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit.

(1) One (1) natural gas, refinery gas, or liquified petroleum gas-fired Process Heater H-1, modified as part of CXHO, rated at 190 MMBtu/hr and vented to stack S/V 210-01.

(2) One (1) Flare Knock-out Drum (D-18) with emissions vented to vessel D-24, which exhausts to flare stack S/V 220-04.

(3) Leaks from process equipment, including one (1) compressor (identified as K1), pumps, valves, process drains and pressure relief devices.

(j) The Aromatic Recovery Unit (ARU), identified as Unit ID 242, consists of the ARU 200 section and the ARU 300 section. The primary function is to remove light ends from naphtha to obtain a more desirable reforming feed. Its secondary function is to separate xylene, a chemical feedstock, from the Ultraformer product. The ARU utilizes a series of distillation towers to purify reformer feed and another

set of towers to separate chemical feedstocks. The ARU includes the following process units and may also include insignificant activities listed in Section A.4 of this permit.

(1) The following process heaters, which are fired with refinery gas, natural gas or liquified petroleum gas.

Heater Identification	Construction Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-200A	1978	249.5	242-01	None
F-200B	1978	249.5	242-02	None

(2) The ARU is connected to the 4UF flare stack, S/V 224-06. The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(3) Leaks from process equipment.

(k) The Blending Oil Unit (BOU), identified as Unit ID 250, uses hydrogen to convert sulfur to hydrogen sulfide and remove it from distillate and gas oil streams to meet product specifications. The hydrogen sulfide is sent to the Claus Trains for further processing. As part of the CXHO Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr. The facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) One process Furnace F-401, constructed in 1972, and modified as part of CXHO, which vents to stack ID S/V250-01. The furnace is rated at 35 million Btu and is fired by natural gas, refinery gas or liquid petroleum gas.

(2) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(l) No. 2 Treatment Plant, identified as unit 601, removes disagreeable odors from various naphtha streams using a catalytic process. This facility has only fugitive emissions and/or other emissions that are considered insignificant.

(m) No. 4 Treatment Plant, identified as unit 602, removes disagreeable odors from various naphtha and distillate streams using a catalytic process. This facility has only fugitive emissions and/or other emissions that are considered insignificant. The No. 4 Treatment Plant will be decommissioned as part of the CXHO project.

(n) Butane, Propane and Propylene Storage and Loading Facilities, identified as Unit ID 604, includes the following sources of emissions and may also include insignificant activities listed in Section A.4 of this permit:

(1) One (1) butane storage cavern located in South Tank Field.

(2) Seven (7) pressurized butane storage spheres located southwest of the main Refinery near the J&L Tank Field with a capacity of 1,050,000 gallons each.

(3) Propane (LPG) storage caverns and above-grade pressurized storage vessels located near the J&L Tank Field.

(4) Propane (LPG) railcar loading facilities located near the J&L Tank Field. These can also be used for loading butane into railcars.

(5) Pressurized polymer grade propylene (PGP) and refinery grade propylene (RGP) storage vessels located at the north east end of the Refinery.

(6) Propylene truck and railcar loading facilities located at the north east end of the Refinery, with emissions vented to the PIB flare, which is owned and operated by INEOS USA, LLC (Plant I.D. 089-00076).

(7) One (1) LPG loading area flare stack having stack number S/V 604-01, installed in 1986, which is used as a safety device which burns any vented gases that might result from relieving pressure on equipment.

(8) Leaks from process equipment.

(o) The No.3 Ultraformer Unit (No. 3 UF), identified as Unit ID 220, commissioned in 1958 The majority of the unit was shutdown in March 2007, including the H-1, H-2 and F-7 heaters, catalyst filled reactors and the internal scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation steps of the regeneration process. The unit consists of the C-2 Splitter Tower, the D-18 flare gas separator, D-24 knock-out drum and associated piping.

(1) One (1) flare gas separator (D-18) with emissions vented to vessel D-24, which exhausts to flare stack S/V 220-04.

(2) Leaks from process equipment, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(p) The No.4 Ultraformer Unit (no. 4 UF), identified as Unit ID 224, built in 1972, upgrades low-octane naphtha to gasoline blending material and chemical feedstocks. The front-end of the unit is a desulfurization section. The reforming section consists of a series of process furnaces and catalyst-filled reactors in which the naphtha is heated and converted from straight chain to aromatic compounds. The reactor products are separated by distillation for further processing or blending into gasoline. A new reactor will be installed as part of the CXHO project. The No. 4 Ultraformer includes the following sources of emissions and may also include insignificant activities listed in Section A.4 of this permit:

(1) Nine (9) process heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-1	68	224-01	None
F-8A	163	224-01	None
F-8B	163	224-01	None
F-2	286	224-02	None

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-3	242	224-03	None
F-4	137	224-03	None
F-5	99	224-04	None
F-6	49	224-04	None
F-7	52	224-05	None

(2) One (1) flare (identified as the 4UF flare), exhausting at stack S/V 224-06. The 4UF flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance, and reactor regenerations.

(3) Six (6) catalyst-filled reactors, which are vented to flare stack S/V 224-06 during the initial catalyst depressuring and catalyst purging steps of the regeneration process.

(4) Leaks from process equipment, including two (2) compressors (identified as K-1 and K-7), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(5) One (1) caustic scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation steps of the regeneration process, which removes HAP emissions. The scrubber system includes:

(A) One (1) caustic scrubber exhausting to stack 224-07;

(B) One (1) carbon adsorption system used to treat waste scrubber liquor prior to disposal; and

(C) Caustic feed unloading, storage, and transfer equipment.

(q) The Hydrogen Unit (HU), identified as Unit ID 698, commissioned in 1993, produces 99+% pure hydrogen needed for the refinery hydrotreating processes. The HU produces high purity hydrogen by reacting steam with methane. The reaction is carried out by heating the mixture in a furnace and reacting it in the presence of a catalyst. The HU includes the following sources of emissions and may also include insignificant activities listed in Section A.4 of this permit:

(1) One (1) natural gas, refinery gas or liquified petroleum gas fired B-501 Process Heater rated at 366.3 MMBtu/hr, which exhausts at stack S/V 698-01. The Process Heater is equipped with low-NO_x burners.

(2) One (1) DDU Flare exhausting at stack S/V 698-02, burning natural gas as the pilot gas, used to control VOC emissions during emergency situations, unit startups and shutdowns and depressuring equipment for maintenance.

(3) Leaks from process equipment.

(r) The Distillate Desulfurizer Unit (DDU), identified as Unit ID 700, commissioned in 1993, removes sulfur from petroleum distillates. Distillate feed is mixed with hydrogen, heated in

process furnaces and passed over a catalyst bed to convert sulfur compounds to H_2S. The DDU includes the following emissions sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) Process Heater WB-301, rated at 64.8 MMBtu/hr and exhausting to stack S/V 700-01. The Process Heater is equipped with low-NO_x burners and burns natural gas, refinery gas, or liquified petroleum gas.

(2) Process Heater WB-302, rated at 83.7 MMBtu/hr and having stack ID S/V 700-02. The Process Heater is equipped with low-NO_x burners and burns natural gas, refinery gas, or liquified petroleum gas

(3) Leaks from process equipment.

(4) The Distillate Desulfurization Unit is connected to the DDU Flare System. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns and depressuring equipment for maintenance.

(s) The Cat Feed Hydrotreating Unit (CFHU), identified as Unit ID 171, built in 1982, removes sulfur from and improves the quality of gas oil feed to the Fluidized Cracking Units. The No. 4 Ultraformer Flare Stack, S/V 224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The CFHU is connected to the No. 4 Ultraformer flare stack. The flare is used to control VOC emissions, unit startups and shutdowns, and preparation of equipment for maintenance. The CFHU includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) Three (3) process heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-801 A/B	66.5	171-01	low-NO_x burners
F-801C	60.0	171-02	ultra low-NO_x burners

(2) Leaks from process equipment.

(t) The Catalytic Refining Unit (CRU), identified as Unit ID 201, which removes sulfur from petroleum naphthas and distillates. Naphtha or distillate feed is mixed with hydrogen, heated in process furnaces and passed over a catalyst bed inside one of two reactor trains, identified as D-114 and D-105, to convert sulfur compounds to hydrogen sulfide. Hydrogen sulfide is subsequently removed from the product by distillation followed by scrubbing with an amine. The CRU includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) Two (2) heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-101	72	201-01	Low-NO_x Burners

F-102A	60	201-02	Low-NO_x Burners

(2) The CRU is connected to the UIU flare stack, S/V 220-04. The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(3) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

Main Operating Scenario:

The CRU operates as a naphtha hydrotreater. Maximum production under this scenario is 27,000 barrels per day.

Alternative Operating Scenario:

The CRU operates as a distillate hydrotreater. Maximum production under this scenario is 40,000 barrels per day.

(u) The Fluidized Catalytic Cracking Unit (FCU) 500, constructed in 1945, identified as Unit ID 230 and rated at 115,000 barrels per day. This facility converts hydrocarbons that boil above 500 ^{o}F into lower molecular weight products, which include gasoline and LPG. The cracking takes place as the gas oil and catalyst stream mix in the reactor. This process results in the catalyst being coated with coke, which is subsequently burned off in a regenerator. The FCU 500 includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) One (1) catalyst regenerator. Flue gas from the regenerator passes through an ammonia injection system, a waste heat recovery unit which generates steam, an Electrostatic Precipitator for particulate matter control, and is exhausted through stack S/V 230-01. The ammonia injection system includes aqueous ammonia injection and handling equipment. Aqueous ammonia is transferred from the FCU 600 SCR system's storage tanks.

(2) Three (3) catalyst storage bins, one each for spent, equilibrium, and fresh catalyst. Particulate emissions from the spent catalyst storage bin, identified as Bin F-52, are controlled by one (1) cyclone, which exhausts to stack S/V 230-03.

(3) One (1) flare exhaust at stack S/V 241-01 (VRU Flare). The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including two (2) compressors (identified as J-3D and J-3G), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system.

(5) As part of the FCU 500 WARP, per SPM 089-25488-00453, the FCU 500 blowdown stack will be shutdown and the pressure relief discharges that vent to the blowdown stack will be re-routed to the VRU flare.

(6) The FCU 500 turnaround (TAR) project, per SPM 089-25488-00453, for the repair or replacement of the power recovery turbine, and the air ring for the catalyst regenerator. The increases in emissions from FCU 500 TAR are already accounted for as CXHO project related emissions increases.

(v) The Fluidized Catalytic Cracking Unit (FCU) 600, constructed in 1946, identified as Unit ID 240 and rated at 80,000 barrels per day. This facility converts hydrocarbons that boil above 500 ^{o}F into lower molecular weight products, which include gasoline and LPG. The cracking takes place as the gas oil and catalyst stream mix in the reactor. This process results in the catalyst being coated with coke, which is subsequently burned off in a regenerator. The FCU 600 includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) One (1) catalyst regenerator. Flue gas from the regenerator passes through a waste heat recovery unit, which generates steam and an Electrostatic Precipitator for particulate matter control. The flue gas is then directed to a selective catalytic reduction (SCR) system, which chemically reduces nitrogen oxide emissions by reaction with injected ammonia, and is exhausted through stack S/V 240-01.

(2) Two catalyst storage bins, one each for equilibrium and fresh catalyst. (Spent catalyst is stored in Bin F-52, which is associated with FCU 500.)

(3) One (1) flare exhausting at stack ID S/V 230-02 (FCU Flare). The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including two (2) wet gas compressors (identified as J-3Dand J-3E), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system.

(5) As part of the FCU 600 WARP, per SPM 089-25488-00453, to shutdown the existing FCU 600 blowdown stack and the pressure relief discharges that were vented to the blowdown stack will be re-routed to the FCU flare.

(6) The FCU 600 turnaround (TAR) project, per SPM 089-25488-00453, for the repair or replacement of the main fractionator overhead condensers, the slurry and pump around system, unit pump replacement, FCU flare tip replacement, and additional controls to reduce plugging on the SCR. The increases in emissions from FCU 600 TAR are already accounted for as CXHO project related emissions increases.

(w) A portion of No. 1 Stanolind Power Station (SPS) constructed in 1928 and identified as Unit ID 501. The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas, are NOx budget units:

(1) The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Boiler Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
#5 Boiler	265	501-02	None
#6 Boiler	265	501-02	None
#7 Boiler	265	501-02	None

Note: The boilers in No. 1 Stanolind Power Station are scheduled to be shut down as part of Consent Decree 2:96 CV 095 RL.

(2) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(x) A portion of No. 3 Stanolind Power Station (SPS) constructed as listed below and identified as Unit ID 503. The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas, are NOx budget units:

(1) The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Boiler Identification	Installation Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
#1 Boiler	1948	575	503-01	(current) low-NO_x burners, an induced flue gas recirculation (IFGR) system, and an over fired air (OFA) system
#2 Boiler	1948	575	503-02	After CXHO: The low-NOx burners, IFGR and OFA will be replaced by conventional burners and a Selective Catalytic Reduction (SCR) system on Boilers # 1, 2, 3, 4, 6
#3 Boiler	1951	575	503-03	
#4 Boiler	1951	575	503-04	
#6 Boiler	1953	575	503-05	

(2) Five (5) direct-fired duct burners, per SPM 089-25488-00453, rated at 41 mmBTU/hr each, equipped with low NOx burners and controlled by a Selective Catalytic Reduction (SCR) system.

(3) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(y) Hazardous Waste Treatment System:

Dewatering and thermal desorption system for processing sludge, per SPM 089-25488-00453, including dissolved air flotation skimmings (DAF) and API oil/water separator sludge, The dewatering system will be equipped with a wet scrubber and carbon canister system and the thermal desorption unit will be equipped with a vapor recovery system to optimize absorption of hydrocarbons. The feed rate capacities at the dewatering system and thermal desorption systems are 22,500 tons of feed per year and 9,000 dry tons of solids per year, respectively. This facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of the permit:

(1) Two (2) centrifuges;

(2) Two (2) sludge surge tanks;

(3) One (1) oil/water mixture surge tank;

(4) One (1) enclosed auger transfer system;

(5) One (1) vapor recovery system on the thermal desorption unit including: an oil condensing/scrubbing system, a water condensing/scrubbing system, and an oil

water separator. Uncondensed vapors from this system are routed to the two (2) diesel fired burners for destruction of VOCs.

Insignificant Activity:

(6) Two (2) diesel fired burners rated at 4 mmBTU/hr each, for the thermal desorption system.

(z) Wastewater Treatment Plant (WWTP), identified as Unit ID 544. This facility treats the water used in the refining process that comes into contact with oil or chemicals. In the first step, the heavier solids are removed at the inlet to the WWTP and the floating oil is skimmed from the surface of the wastewater in the API separator boxes. The oil is then recycled back to the refinery. The water is then aerated in the Air Flotation Unit where additional solid impurities are floated and skimmed. Thereafter, it moves to the Activated Sludge Plant where special bacteria digest the remaining contaminants. The water then passes through a clarifier and then eight (8) final filters before being returned to Lake Michigan. This facility includes the following emission sources and may also include insignificant activities listed in section A.4 of this permit:

(1) The following units are equipped with closed vent systems: oil sump P-1, oil sump P-2, and Diffused Air Floatation (DAF) Secondary Boxes, which vent to a biofilter and carbon canisters; Tank 569 is equipped with a conservation vent.

(2) The following units are equipped with a fixed-roof or floating roof: Interceptor Box, Diversion Box (from Tank 5051 to DAF), DAF Flash Mixer, DAF Influent Channel, DAF Effluent Channel, DAF Primary Boxes, and DAF Sump.

(3) One (1) storage tank (identified as Tank 5051) having a maximum storage capacity of 10,000,000 gallons, constructed in 1988 and equipped with an external floating roof.

(4) One (1) storage tank (identified as Tank 5050) having a maximum storage capacity of 10,000,000 gallons, constructed in 1988. This tank is used for storm event and upset impoundments.

(5) Seven (7) oil-water/solids separator units enclosed with a fixed-roof: Bar Screen, #7 API Separator Fixed Cover, #7 API Separator Primary Inlet, #7 API Separator Secondary Inlet, #7 API Separator Secondary Outlet, #7 API Separator Inlet Channel Section, and #7 API Separator Gear Boxes.

(6) One (1) storage tank (identified as Tank 5052) having a maximum storage capacity of 11,676,000 gallons, to be constructed as part of the CXHO Project. This tank will be used as a stormwater equalization tank and is equipped with an external floating roof.

(7) A brine treatment system with seven (7) wastewater tanks with vertical fixed roofs, constructed as part of CXHO project, identified as:

(A) TK-105A, with a storage capacity of 867,180 gallons;
(B) TK-105B, with a storage capacity of 867,180 gallons;
(C) TK-101, with a storage capacity of 66,096 gallons;
(D) TK-102, with a storage capacity of 66,096 gallons;
(E) TK-103, with a storage capacity of 66,096 gallons;
(F) TK-104A, with a storage capacity of 89,943 gallons; and
(G) TK-104B, with a storage capacity of 89,943 gallons.

(aa) Oil Movements, identified as Unit 640. This facility is used to store, blend, and ship products. Gasoline blending components are custom blended into various grades of gasoline. Additive and other compounds are blended into the products to give them their unique characteristics. Furnace oil and other distillates are also blended using components from process units or storage. Crude oil and feedstocks for process units and products are also stored at this location. Product loading operations include the pipeline and railcar racks. This facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) One (1) internal floating roof storage tank identified as 3730, storing ethanol, constructed in 1955, with a maximum storage capacity of 1,050,721 gallons.

(2) Ten (10) external floating roof storage tanks storing petroleum hydrocarbon with vapor pressure less than 15 psia, comprising the following tanks:

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3529	1948	858,000
3637	1956 permitted in 2008 for reconstruction (SPM 089-25488-00453)	6,353,000
3901	1956	1,906,000
3902	1956	1,906,000
3915	1980	6,353,460
3916	1980	13,666,998
3917	1980	25,413,839
3918	1980	13,666,998
3919	1980	13,666,998
3920	1980	13,666,998

(3) Sixty-seven (67) internal floating roof storage tanks, storing petroleum hydrocarbon with vapor pressure less than 15 psia, comprising the following tanks:

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3474	1992	3,734,422
3475	1994	3,865,445
3476	1984	3,085,016
3477	1971	4,066,214
3480	1982	4,026,505
3482	1972	169,426

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3483	1924	3,382,264
3484	1996	3,865,445
3486	1979	4,026,505
3487	1980	4,026,505
3488	1994	3,865,445
3489	1996	3,865,445
3492	1925/1971	3,382,000
3493	1995	3,865,445
3510	1949	4,235,640
3511	1973	4,066,214
3512	1958	4,066,214
3513	1971	4,066,214
3514	1984	4,066,214
3525	1981	4,026,505
3526	1943/1979	4,026,505
3527	1991	3,382,264
3528	1993	3,865,445
3531	1948/1997	857,717
3532	1953	868,306
3533	1953	4,235,640
3534	1955/1973	71,000
3549	1993	588,283
3553	1981	5,070,343
3554	1981	5,070,343
3558	1972/1986	376,501
3600	1993	847,128
3601	1977	3,702,020
3602	1979	3,856,271
3604	1980	3,856,271
3605	1977	3,702,000

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3622	1993	3,865,445
3624	1932	3,382,264
3629	1992	3,865,445
3631	1944	3,382,000
3633	1950	5,282,000
3635	1954	5,070,000
3639	1956	6,353,460
3641	1956	6,353,460
3701	1943/1993	3,382,264
3702	1943/1982/1997	3,382,264
3703	1944/1982	3,382,264
3704	1944/1980	3,382,264
3705	1944	3,382,264
3706	1944	3,382,264
3707	1944/2000	3,382,264
3708	1943	853,895
3709	1943	825,434
3710	1943	2,059,000
3715	1945/1987/1998	3,382,264
3716	1996	3,865,445
3727	1948	857,717
3728	1970	857,717
3860	1993	211,782
3900	1956/2005	1,906,000
3904	1956/1986	3,388,512
3905	1956	6,353,460
3907	1956/1996	3,388,512
3909	1956	3,388,512
3911	1956/1986	3,388,512
3912	1956	6,353,460

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3914	1956	3,388,512

(4) Miscellaneous Storage tanks including the following:

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	Vapor Pressure of Liquid (psia)
D-424	4ULTRAFORMER	Methanol Tank	--	3,744	<0.5
F-011	4B TREATER	Casper Dewaterer	1949	17,624	<0.5
TK-0563	INCINERATOR	Aux. Fuel Oil	1971	49,378	<0.5
TK-3228	CRUDE STA	Decanted Oil	1948	596,570	<0.5
TK-3234	CRUDE STA	Decanted Oil	1940	858,298	<0.5
TK-3464	BERRY LAKE	Decanted Oil	1957	2,705,472	<0.5
TK-3465	BERRY LAKE	Plant Fuel	1973	3,413,088	<0.5
TK-3468	BERRY LAKE	TGO	1958	3,381,840	<0.5
TK-3491	SO. TK FLD.	Lsho	1992	3,876,768	<0.5
TK-3496	SO. TK FLD.	Distillate	1992	3,876,768	<0.5
TK-3498	SO. TK FLD.	Amoco Premier Diesel [Future Lsfo]	1929	3,373,413	<0.5
TK-3499	SO. TK FLD.	Amoco Premier Diesel [Future Lsfo]	1996	3,870,720	<0.5
TK-3500	SO. TK FLD.	Furnace Oil [Future Hmd]	1996	3,870,720	<0.5
TK-3505	SO. ANNEX	Heater Oil	1949	4,254,768	<0.5
TK-3509	SO. TK FLD.	Furnace Oil	1948	3,381,840	<0.5
TK-3546	SO. TK FLD.	Bronze Dye	1962	16,800	<0.5
TK-3547	SO. TK FLD.	Purple Dye	1962	16,800	<0.5
TK-3548	SO. TK FLD.	Isonox 133	1962	16,800	<0.5
TK3567	--	--	--	17,000	<0.5
TK-3569	MARINE DOCK	DCO	1981	4,796,064	<0.5
TK-3571	MARINE DOCK	HS Resid/Black Oil	1971	5,539,968	>0.5 and <0.75
TK-3572	MARINE DOCK	HS Resid/Black Oil	1971	5,539,968	>0.5 and <0.75
TK-3606	STIGLITZ PK.	Amoco Jet Fuel A [New 1996]	1996	3,701,376	<0.5
TK-3607	STIGLITZ PK.	Amoco Jet Fuel A	1993	3,729,600	<0.5
TK-3609	STIGLITZ PK.	HS Resid	1973	9,652,608	<0.5
TK-3610	STIGLITZ PK.	HS Resid	1973	9,652,608	<0.5
TK-3611	STIGLITZ PK.	HS Resid	1973	8,513,400	<0.5
TK-3613	STIGLITZ PK.	HS Resid	1992	3,876,768	<0.5
TK-3711	IND. TK FLD.	Lcco	1993	2,818,368	<0.5
TK-3712	IND. TK FLD.	Lcco	1945	3,357,600	<0.5
TK-3714	IND. TK FLD.	Distillate/Gas Oil	1999	3,852,576	<0.5
TK-3717	IND. TK FLD.	Fcu Feed Mixed	1943	3,263,190	<0.5
TK-3718	IND. TK FLD.	Gas Oil	1996	3,871,379	<0.5
TK-3719	IND. TK FLD.	Gas Oil	1943	3,357,600	<0.5
TK-3720	IND. TK FLD.	Gas Oil	1946	3,357,600	<0.5

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	Vapor Pressure of Liquid (psia)
TK-3721	IND. TK FLD.	Gas Oil	1946	3,357,600	<0.5
TK-3722	IND. TK FLD.	Gas Oil	1952	4,227,300	<0.5
TK-3723	IND. TK FLD.	Gas Oil	1954	3,386,880	<0.5
TK-3726	IND. TK FLD.	Amoco Jet Fuel A	1948	857,356	<0.5
TK-3733	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,383,520	<0.5
TK-3734	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,383,520	>0.5 and <0.75
TK-3735	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,411,072	<0.5
TK-3867	SO. TK FLD.	Stadis 450	1967	17,640	<0.5
TK-3868	SO. TK FLD.	Amogard	1953	17,640	>0.5 and <0.75
TK-3869	SO. TK FLD.	Pour Depressant	1956	23,436	<0.5
TK-3872	CRUDE STA	Used Motor Oil	1985	15,120	<0.5
TK3876	South TF	Cetane Improver	1993	14,381	<0.5
TK-3906	J&L TK FLD.	Lsfo	1956	3,381,840	>0.5 and <0.75
TK-3908	J&L TK FLD.	Amoco Premier Diesel	1956	3,381,840	<0.5
TK-3910	J&L TK FLD.	Furnace Oil [Hs]	1956	3,381,840	<0.5
TK-3913	J&L TK FLD.	Furnace Oil [Ls]	1956	3,402,977	<0.5
TK-6078	ASPHALT	HS Resid/Black Oil	1948	1,931,000	<0.5
TK-6113	ASPHALT	Paving Base	1944	810,600	<0.5
TK-6114	ASPHALT	Paving Base	1944	810,600	<0.5
TK-6125		Paving Base	1998	3108932	<0.5
TK-6126		Paving Base	1999	3,108,000	<0.5
TK-6127		Paving Base	2000	3,108,000	<0.5
TK-6128		Paving Base	1971	3,225,600	<0.5
TK-6129		Paving Base	2005	3,108,000	<0.5
TK-6148		Paving Base	1948	3,108,000	<0.5
TK-6149		Paving Base	1948	3,108,000	<0.5
TK-6150		HS Resid	1986	810,600	<0.5
TK-6153		HS Resid	1979	1,386,000	<0.5
TK-6248	ASPHALT	Low Sul Resid	1973	7,218,928	<0.5
TK-6249	ASPHALT	Low Sul Resid	1973	7,218,928	<0.5
TK-6250	ASPHALT	HS Resid	1971	7,218,928	<0.5
TK-6251	ASPHALT	Paving Base	1971	7,218,928	<0.5
TK-6252	ASPHALT	HS Resid	1972	7,215,268	<0.5
TK-6253	ASPHALT	Paving Base	1971	7,218,928	<0.5
TK-6261	ASPHALT	HS Resid	1973	451,183	<0.5
TK-6262	ASPHALT	HS Resid	1972	451,183	<0.5
TK-0559	ASU	Out of Service	1989	146,869	--
TK-0560	ASU	Out of Service	1948	587,477	--
TK-0568		Out of Service	Before 1973	--	--
TK-3167		Out of Service	1926	3,361,114	--
TK-3168		Out of Service	1926	1,931,170	--
TK-3169		Out of Service	1926	3,361,114	--
TK-3232	CRUDE STA	Out of Service	1940	857,356	--
TK-3259	CRUDE STA	Out of Service	1951	846,720	--
TK-3260	CRUDE STA	Out of Service	1930	375,986	--
TK-3279	MARINE DOCK	Out of Service	1951	85,302	--
TK-3309	CRUDE STA	Out of Service	NA	7,050	--

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	Vapor Pressure of Liquid (psia)
TK-3373		Out of Service	--	--	--
TK-3471	SO. TK FLD.	Out of Service	1973	7,050	--
TK-3485	SO. TK FLD.	Out of Service	1924	3,373,413	--
TK-3494	SO. TK FLD.	Out of Service	1926	3,373,413	--
TK-3497	SO. TK FLD.	Out of Service	1926	3,373,413	--
TK-3506	SO. ANNEX	Out of Service	1936	3,373,413	--
TK-3507	SO. ANNEX	Out of Service	1936	3,373,413	--
TK-3508	SO. ANNEX	Out of Service	1936	3,366,720	--
TK-3603	STIGLITZ PK.	Out of Service	1922	3,084,480	--
TK-3608	STIGLITZ PK.	Out of Service	1954	3,849,300	--
TK-3713	IND. TK FLD.	Out of Service	1944	3,357,600	--
TK-3903	J&L TK FLD.	Out of Service	1956	3,381,840	--
TK-6222		Out of Service	--	3,000	--
TK-6223		Out of Service	--	211,400	--
TK-6224		Out of Service	--	211,400	--
W-306	MWTP	Out of Service	--	--	--

"--" - no data provided.

(5) One (1) oil-water separator identified as the J&L Separator.

(6) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(bb) The general facility remediation system, identified as Unit 999. Remediation includes multiple well point systems. The well point system extracts groundwater which may have a small hydrocarbon fraction. Depending on the VOC concentration, emissions generated by these systems may be routed to the atmosphere or to a thermal oxidizer. Additionally, one or more systems may route to the same oxidizer. Each system uses a common horizontal vacuum header to collect groundwater through a series of wells, and any entrained air is discharged through a vent at the vacuum pump. Recovered groundwater is then transferred to either a vapor/liquid separation tank or directly to another unit for further processing/treatment. Remediation includes the following emission sources and may also include insignificant activities listed in section A.4 of this permit.

(1) The following well point systems:

Facility I.D.	Installation Date	S/V I.D.	Normal Venting	Controls
J-136	1993	999-01	Vented Separately	Uncontrolled
J-137	1992	999-02	Vented Separately	Uncontrolled
J-138	1991 Extension 1994	999-03	J-138, J-139 and J-140 are vented with D-138 (vapor/liquid separation tank)	0.685 MMBtu per hour Thermal Oxidizer ITF
J-139	1981	999-04		
J-140	1981	999-05		
J-141	1988 Extension 1993	999-06	Vented Separately	Uncontrolled
J-156	1968-1970	999-07	Vented Separately	Uncontrolled

Facility I.D.	Installation Date	S/V I.D.	Normal Venting	Controls
J-157	1968-1970	999-08	Vented Separately	Uncontrolled
J-158	1968-1970	999-10	J-158, & J-159 vents are common	Electric Catalytic Oxidizer 600 ^{o}F min. temp., @ 1,000 scfm
J-159	1968-1970	999-11		
J-160	1968-1970 Extension 1994	999-12	Vented Separately	Electric Catalytic Oxidizer, 600 ^{o}F min. temp., @ 1,000 acfm
J-161	1992	999-13	Vented Separately	0.685 MMBtu per hour Thermal Oxidizer BLTF
J-162	1996	999-14	Vented Separately	Uncontrolled
J-163	1996	999-15	Vented Separately	Uncontrolled

(cc) The Mechanical Shop, identified as Unit 693. The Mechanical Shop includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) Two (2) Heat Treat Furnaces that are considered insignificant sources.

(2) Leaks from facility fuel gas lines.

(dd) One bulk truck loading facility, identified as the Marketing Terminal, and consisting of one (1) truck loading rack, constructed in 1972 and modified in 1992, comprised of 7 bays used for loading gasoline products and fuel oil. Four bays are dedicated to loading distillates, while the other three bays are dedicated to loading gasoline products. The maximum throughput for the truck loading facility is 1,103,760,000 gallons per year. Emissions of volatile organic compounds are controlled using a vapor combustion unit (identified as VCU).

(ee) Cooling Towers including the following:

(1) One (1) cooling tower (identified as Cooling Tower No.6), constructed in 1996, with a maximum capacity of 20,000 gallons of water per minute. Cooling Tower No.6 is located at the No.12 Pipestill.

(2) Cooling Towers (constructed prior to 1980), with controls installed as part of the CXHO project:

Cooling Tower	Recirculation Rate/Make-up rate (gallons/minute)	Control Devices
Cooling Tower 2*	25,000/1,285	high efficiency liquid drift eliminators

Cooling Tower 3	90,000/1,571	high efficiency liquid drift eliminators
Cooling Tower 4	44,000/1,085	high efficiency liquid drift eliminators

* Half of the Cooling Tower 2 modules were controlled prior to the CXHO Project. Contemporaneous to the CXHO Project the other modules will be controlled with high efficiency drift eliminators.

(3) Cooling Towers to be installed as part of the CXHO project:

Cooling Tower	Recirculation Rate/Make-up rate (gallons/minute)	Control Devices
Cooling Tower 7	21,000/451	high efficiency liquid drift eliminators
Cooling Tower 8	90,000/2956	high efficiency liquid drift eliminators

(ff) One (1) Asphalt Facility used to store, blend and transfer asphalt products. The facility has six blenders used for loading asphalt into railcars and trucks. Process heaters are used to keep certain tanks at the proper temperature for shipping. This facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) The following two (2) process heaters:

Process Heater ID	Heat Input Capacity (MMBtu/hr)	Fuel	Control Device
F-1 Asphalt Heater	12	Natural gas	none
F-2 Steiglitz Park Heater	28	Natural gas	none

(2) The following seven (7) asphalt storage tanks used to store volatile organic liquids that have a vapor pressure less than 0.75 psi:

Identification	**Storage Capacity (gallons)**	**Year Constructed**
125	3,108,000	1998
126	3,108,000	1999
127	3,108,000	2000
129	3,108,000	2003
150	1,386,000	1986
569	5,544,000	1981
613	8,866,200	1992

(3) The following twenty-five (25) asphalt storage tanks used to store volatile organic liquids that have a vapor pressure less than 0.5 psi.

Identification	**Storage Capacity (gallons)**	**Year Constructed**
78	1,814,400	1947
113	810,600	1944
114	810,600	1944
128	3,225,600	1971
148	810,600	1948
149	810,600	1948
153	932,400	1979
222	210,000	1955
223	210,000	1955
224	210,000	1955

225	361,200	1950
248	6,967,800	1973
249	6,967,800	1973
250	6,967,800	1971
251	6,967,800	1971
252	6,967,800	1972
253	6,967,800	1971
261	441,000	1973
262	441,000	1972
468	3,108,000	1956
571	5,040,000	1971
572	5,040,000	1971
609	5,649,000	1973
611	8,513,400	1973

(4) The following twenty-two (22) heated vertical storage tanks, each approved for construction in 2007, each with a fixed cone roof, and each in heavy liquid service, storing volatile organic liquids that have a vapor pressure less than 0.0435 psia, and exhausting to the atmosphere or to a biofilter system for odor and opacity control:

Tank ID	Liquid Stored	Date Approved for Construction	Tank Storage Capacity (gallons)	Maximum Throughput (gallons/year)	Exhaust ID
TK-3573	Trim Gas Oil	2007	966,000	20,160,000	TK-3573
TK-SP-1	Residual Oil and/or Asphalt	2007	14,154,000	141,120,000	biofilter
TK-SP-2	Residual Oil and/or Asphalt	2007	14,154,000	141,120,000	biofilter
TK-SP-3	Trim Gas Oil	2007	2,268,000	16,800,000	biofilter
TK-SP-4	Trim Gas Oil	2007	2,268,000	16,800,000	biofilter
TK-LG-1	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-2	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-3	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-4	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-5	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-6	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-7	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-8	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-9	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-10	Trim Gas Oil	2007	2,268,000	16,800,000	biofilter
TK-LG-11	Trim Gas Oil	2007	2,268,000	16,800,000	biofilter
TK-LG-12	Asphalt with Polymer	2007	2,100	420,000	biofilter

Tank ID	Liquid Stored	Date Approved for Construction	Tank Storage Capacity (gallons)	Maximum Throughput (gallons/year)	Exhaust ID
TK-LG-13	Asphalt-Polymer Blend	2007	31,500	2,100,000	biofilter
TK-LG-14	Polymer Finished Asphalt	2007	126,000	2,520,000	biofilter
TK-LG-15	Polymer Finished Asphalt	2007	126,000	2,520,000	biofilter
TK-LG-16	Polymer Finished Asphalt	2007	126,000	2,520,000	biofilter
TK-LG-17	Polymer Finished Asphalt	2007	126,000	2,520,000	biofilter

Under 40 CFR 60, Subpart UU, storage tanks TK-SP-1, TK-SP-2, TK-LG-1 through TK-LG-9, and TK-LG-12 through TK-LG-17 are each considered an affected facility.

Under 40 CFR 63, Subpart CC, storage tanks TK-3573, TK-SP-1 through TK-SP-4, TK-LG-1 through TK-LG-17 are each considered as Group 2 storage vessels that are part of the existing affected source.

(5) The following heated vertical storage tank, with a fixed cone roof, in heavy liquid service, storing volatile organic liquids that have a vapor pressure less than 0.0435 psia, and exhausting to the atmosphere:

Tank ID	Liquid Stored	Construction Date	Tank Storage Capacity (gallons)	Maximum Throughput (gallons/year)	Exhaust ID
TK-3570	Trim Gas Oil	1971	2,730,000	20,160,000	TK-3570

Under 40 CFR 63, Subpart CC, storage tank TK-3570 is considered as a Group 2 storage vessel that is part of the existing affected source.

(6) one (1) truck loading rack, approved for construction in 2007, comprised of six (6) loading bays used for loading liquid asphalt product, with a total maximum loading capacity of 800,000 tons of asphalt product per year, exhausting to the atmosphere or to a biofilter system for odor control.

(7) one (1) rail car loading rack, approved for construction in 2007, comprised of twenty-eight (28) loading bays used for loading liquid asphalt product, with a total maximum loading capacity of 800,000 tons of asphalt product per year, exhausting to the atmosphere or to a biofilter system for odor control.

(8) Equipment leaks of VOC and HAP from valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, flanges and/or other connectors.

Under 40 CFR 60, Subpart GGG, valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, flanges and/or other connectors in VOC service, are considered part of the existing affected source.

(gg) One (1) pipeline (Cogen Steam Transfer Line) connecting BP's boilers (identified as emission units 501 and 503) with Whiting Clean Energy's heat recovery steam operator. The pipeline is used to exchange steam between the two facilities. The pipeline was constructed in 2001.

(hh) One (1) pipeline (US Steel Stream Transfer Line) connecting BP's steam header with US Steel East Chicago (Plant ID #089-00300). This pipeline was constructed 2005 through 2006 and is used to transfer steam from BP to US Steel.

(ii) One (1) Marine Dock Facility used to store and transfer products. The facility has three dock berths. A process heater is used to keep certain tanks at the proper temperature for shipping. As part of the CXHO Project, a vapor recovery/control system will be installed on the Marine Dock Loading operations to control emissions from gasoline loading. This facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) One (1) natural gas-fired process heater (identified as Marine Dock Heater F-100), having a maximum heat input capacity of 7 MMBtu per hour.

(2) One (1) storage tank (identified as BT-1), constructed in 1990, with a maximum storage capacity of 706,000 gallons and used to store petroleum hydrocarbons with a vapor pressure less than 15 psia. The tank is equipped with a fixed roof and an internal floating roof.

(3) One storage tank (BT-002), constructed in 1968, permitted for modification in 2008, with a maximum storage capacity of 874,944 gallons, used to store petroleum hydrocarbons with a vapor pressure less than 15 psia, with a fixed roof and an internal floating roof.

(jj) The refinery operates ten eleven hydrocarbon flares. The PIB flare is operated by INEOS. The flares are used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

The flares are identified as follows:

Flare	Stack ID.	Date of Installation	Dimensions	Process Units Normally Controlled by the Flare System *	Maximum Capacity (MMBtu/hr)	Pilot Fuel Type
4UF Flare	224-06	1972	H = 200 ft, D = 2.5 ft.	ARU, CFU, BOU, 4UF	15,000	Fuel Gas and Natural Gas
FCU flare	230-02	1945	H = 200 ft. D = 2.0 ft.	FCU 600	5620	Fuel Gas and Natural Gas
UIU Flare	220-04	1958	H = 199.5 ft. D = 2.5 ft.	ISOM, 3UF, 2TP, CRU	7550	Fuel Gas and Natural Gas
VRU Flare	241-01	Unknown	H = 200 ft. D = 2.0 ft.	VRU 100,VRU200, VRU 300, FCU 500	1596	Fuel Gas and Natural Gas
Alky Flare	140-01	1961	H = 199.5 ft D = 2.5 ft.	PCU, Alky	3920	Fuel Gas and Natural Gas
SRU Flare	162-03	1971	H = 300 ft. D = 1.5 ft.	SRU	688	Fuel Gas and Natural Gas

Flare	Stack ID.	Date of Installation	Dimensions	Process Units Normally Controlled by the Flare System *	Maximum Capacity (MMBtu/hr)	Pilot Fuel Type
DDU Flare	698-02	1993	H = 200 ft. D = 1.5 ft.	DDU, HU, Coker, DHT	6000	Fuel Gas and Natural Gas
LPG Flare	604-01	1986	H = 50 ft. D = 1.2 ft.	LPG storage vessels and loading facilities	30	LPG
PIB Flare**	2	1982	H = 250 ft. D = 3.0 ft.	RGP/PGP Loading Rack	540,000 lb/hr	Fuel Gas and Natural Gas
GOHT Flare***	802-03	Installed as Part of CXHO	H = 316 ft. D = 3.5 ft	GOHT	TBD	Fuel Gas and Natural Gas
South Flare***	800-04	Installed as Part of CXHO	H = 350 ft. D = 5 ft	New Coker (#2 Coker), 12PS, Sulfur Recovery Complex	TBD	Fuel Gas and Natural Gas

* - During emergencies or flare outages, some emission units or streams may be controlled by an alternate flare system that complies with the same applicable requirements as the flare normally used to control the emissions for those units.
** - Owned and operated by INEOS USA, LLC. (Plant I.D. 089-00076).
***** - Flares are equipped with a flare gas recovery system. Under normal operation the recovered gas streams will be sent to vapor recovery/treating area for removal of H2S and heavy components before being utilized in the refinery fuel gas system.**

(kk) The OSBL area includes the pipe alleys, laboratory dock and waste transfer pad. The pipe alleys contain pipes that transfer hydrocarbon streams from one process unit to another or to storage. This facility includes leaks from process equipment, including open-ended valves or lines and flanges. This facility also contains area drains and an oil/water separator. This facility may also include insignificant activities listed in section A.4 of this permit.

(ll) The Distillate Hydrotreating (DHT) Unit, identified as Unit ID 720 and rated at 45,000 barrels per day, which removes sulfur from petroleum distillates. Distillate feed is mixed with hydrogen, heated in a process furnace and passed over a catalyst bed to convert sulfur compounds to H_2S. The DHT Unit was constructed in 2005/2006 and includes the following emission units:

(1) DHT Unit Heater B-601, rated at 20 MMBtu per hour and constructed in May 2005. As part of the CXHO Project, DHT Unit Heater B-601 will be replaced with a 41.9 MMBtu per hour natural gas fired heater, identified as B-601A. NO_X emissions are controlled by ultra low-NO_X burners having an emission rate of 0.04 pounds per million Btu heat input or less. Emissions are exhausted to a stack identified as 720-01.

(2) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

The DHT Unit shares the DDU Flare, used to control VOC emissions during emergency situations, unit startups and shutdowns.

(mm) The Gas Oil Hydrotreater (GOHT) Unit, identified as Unit ID 802 and rated at 120,000 barrels per day. The GOHT reduces the sulfur and nitrogen content of the FCU feed and improves the hydrogen content. Operation of the GOHT will enable the FCU to meet

gasoline sulfur specifications and to improve FCU conversion yields. The GOHT Unit will be constructed as part of the CXHO Project and includes the following emission units:

(1) Process heaters comprising of:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-901A	47	802-01	Ultra low-NO_X burners
F-901B	47	802-02	Ultra low-NO_X burners

(2) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(2) The GOHT Unit vents to the GOHT Flare, used to control VOC emissions during emergency situations, unit startups and shutdowns.

(nn) The New Hydrogen (New HU), identified as Unit ID 801 constructed as part of the CXHO Project, produces 99+% pure hydrogen needed for the refinery hydrotreating processes. The New HU produces high purity hydrogen by reacting steam with methane. The New HU heaters HU-1 and HU-2 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New HU heater stacks have continuous emissions monitors (CEMs) for NOx and CO. The New HU includes the following sources of emissions and may also include insignificant activities listed in Section A.4 of this permit:

(1) Process heaters comprising:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted to	Emission Controls
HU-1	920*	801-01	Low-NO_X burners and selective catalytic reduction
HU-2	920*	801-02	Low-NO_X burners and selective catalytic reduction

* HU Heaters HU-1 and HU-2 combust both natural gas and PSA tail gas with a fuel ratio of no more than 25% natural gas and the remainder PSA tail gas.

(2) One cooling tower (HU Cooling Tower) rated at 2,000 gallons per minute recirculation rate controlled by high efficiency drift eliminators.

(3) The new Hydrogen Unit is connected to the HU Flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The HU Flare will be operated with a water seal or nitrogen purge. As such, there will be no purge gas emissions from the HU Flare. The HU Flare exhausts to S/V 801-03.

(4) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(oo) Two (2) new boilers, identified as New Boiler 1 and New Boiler 2, per SPM 089-25488-00453, each rated at 580 million BTU per hour, equipped with low-NOx burners and/or Selective Catalytic Reduction (SCR) for control of NOx, using either blended natural gas and refinery gas or only refinery fuel gas. A separate TRS CEMS shall be installed to measure the sulfur content of the fuel gas or fuel gas-natural gas blend fed to New Boiler 1 and New Boiler 2.

A.4 Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)]

This stationary source also includes the following insignificant activities, as defined in 326 IAC 2-7-1(21):

(a) Paved and unpaved roads and parking lots with public access, including road sweeping [326 IAC 6.8-10-3] [326 IAC 2-7-1(21)(G)(xiii)];

(b) Asbestos abatement projects regulated by 326 IAC 14-10 [326 IAC 2-7-1(21)(G)(xvi)];

(c) The following equipment related to manufacturing activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment [326 IAC 6.8-1-2(a)] [326 IAC 2-7-1(21)(G)(vi)(EE)];

(d) Machining where an aqueous cutting coolant continuously floods the machining interface [326 IAC 6.8-1-2(a)] [326 IAC 2-7-1(21)(G)(vi)(BB)];

(e) Stockpiled soils from soil remediation activities that are covered and waiting transport for disposal [326 IAC 6.8-10-3] [326 IAC 2-7-1(21)(G)(xii)];

(f) Emission units with PM and PM_{10} emissions less than five (5) tons per year, SO_2, NO_x, and VOC emissions less than ten (10) tons per year, CO emissions less than twenty-five (25) tons per year, lead emissions less than two-tenths (0.2) tons per year, single HAP emissions less than one (1) ton per year, and combination of HAPs emissions less than two and a half (2.5) tons per year [326 IAC 2-1.1-3(e)(1) and 326 IAC 2-7-1(21)(A)-(C)]:

(1) FCU catalyst handling including truck loading/unloading [326 IAC 6.8-1-2(a)];

(2) Power Station soot blows [326 IAC 6.8-1-2(a)];

(3) General excavations for site remediation activities [326 IAC 6.8-10-3];

(4) Fugitive dust from coke yard, sulfur piles, and sulfur pits [326 IAC 6.8-10-3]; and

(5) Soil Screening [326 IAC 6.8-10-3].

(g) Emissions from a laboratory, as defined in 326 IAC 2-7-1(21)(D).

(h) Combustion activities related to the following [326 IAC 2-7-1(21)(G)(i)]:

(1) Space heaters, process heaters, heat treat furnaces, or boilers using the following fuels:

(i) Natural gas, provided the heat input of the unit is equal to or less than 10 MMBtu/hr.

(ii) The following five (5) natural gas-fired hot oil heaters, each approved for construction in 2007, and each considered an insignificant activity, as defined in 326 IAC 2-7-1(21)(G)(i)(AA)(aa):

Process Heater ID	Heat Input Capacity (MMBtu/hr)	Fuel	Control Device
H-SP-1	9.9	Natural gas	none
H-SP-2	9.9	Natural gas	none
H-LG-1	9.9	Natural gas	none

H-LG-2	9.9	Natural gas	none
H-LG-3*	9.9	Natural gas	none

*Hot oil heater H-LG-3 will exhaust to a steam generator that will be used to heat rejected loads of asphalt during unloading.

(iii) Propane, liquified petroleum gas, or butane, provided the heat input of the unit is equal to or less than 6 MMBtu/hr.

(iv) Fuel oil, provided the heat input of the unit is equal to or less than 2 MMBtu/hr and the fuel contains equal to or less than 0.5% sulfur by weight.

(2) Equipment powered by diesel fuel fired or natural gas fired internal combustion engines of capacity equip to or less than 500,000 Btu per hour.

(3) Combustion source flame safety purging on startup.

(i) One (1) fuel dispensing operation, constructed in 2005, dispensing less than or equal to 1,300 gal/day into motor vehicle fuel tanks and with emissions less than the insignificant activity emission thresholds in 326 IAC 2-7-1(21)(A) through (C). The dispensing facility consists of a vapor balance system to control emissions and the following two (2) storage tanks [326 IAC 8-4-6]:

(A) One (1) gasoline storage tank, constructed in 2005, having a maximum storage capacity of 12,000 gallons.

(B) One (1) diesel storage tank, constructed in 2005, having a maximum storage capacity of 6,000 gallons.

(j) The following VOC and HAP storage containers [326 IAC 2-7-1(21)(G)(iii)]:

(1) Storage tanks with capacity less than or equal to one thousand (1,000) gallons and annual throughputs equal to or less than twelve thousand (12,000) gallons.

(2) Vessels storing lubricating oils, hydraulic oils, machining oils, or machining fluids.

(k) Production related activities, including the application of oils, greases, lubricants, and non-volatile material such as temporary protective coatings [326 IAC 2-7-1(21)(G)(vi)(AA)].

(l) Degreasing operations that do not exceed 145 gallons per twelve (12) months, except if subject to 326 IAC 20-6 [326 IAC 2-7-1(21)(G)(vi)(CC)] [326 IAC 8-3-2] [326 IAC 8-3-5].

(m) Cleaners and solvents with a vapor pressure equal to or less than 0.3 psia at 100°F or 0.1 psia at 68°F and for which the combined use for all materials does not exceed 145 gallons per 12 months [326 IAC 2-7-1(21)(G)(vi)(DD)].

(n) Closed loop heating and cooling systems [326 IAC 2-7-1(21)(G)(vi)(FF)].

(o) Ground water oil recovery wells [326 IAC 2-7-1(21)(G)(vii)(BB)].

(p) Activities associated with the treatment of wastewater streams with an oil and grease content less than or equal to 1% by volume [326 IAC 2-7-1(21)(G)(ix)(AA)].

(q) Water run-off ponds for petroleum coke-cutting and coke storage piles [326 IAC 2-7-1(21)(G)(viii)(BB)].

(r) Any operation using aqueous solvents containing less than or equal to 1% by weight of VOCs excluding HAPs [326 IAC 2-7-1(21)(G)(viii)(DD)].

(s) Non-contact cooling tower systems with either natural draft or forced and induced draft systems not regulated under a NESHAP [326 IAC 2-7-1(21)(G)(viii)(FF)].

(t) Activities associates with the transportation and treatment of sanitary sewage, provided discharge to the treatment plant is under the control of the owner or operator, that is, an on-site sewage treatment facility [326 IAC 2-7-1(21)(G)(viii)(CC)].

(u) Repair activities including the following [326 IAC 2-7-1(21)(G)(x)]:

(1) Replacement or repair of ESPs, bags in baghouses, and filters in other air filtration equipment.

(2) Heat exchanger cleaning and repair.

(3) Process vessel degassing and cleaning to prepare for internal repairs.

(v) Coke conveying operations, as provided in 326 IAC 2-7-1(21)(G)(xiv).

(w) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including catch tanks, temporary liquid separators, tanks, and fluid handling equipment [326 IAC 2-7-1(21)(G)(xix)].

(x) Blowdown for sight glasses, boilers, cooling towers, compressors, or pumps [326 IAC 2-7-1(21)(G)(xx)].

(y) Emergency generators meeting one of the following criteria [326 IAC 2-7-1(21)(G)(xxii)(BB)]:

(1) Gasoline generators not exceeding 110 horsepower.

(2) Diesel generators not exceeding 1,600 horsepower.

(3) Natural gas turbines or reciprocating engines not exceeding 16,000 horsepower.

(z) Other activities associated with emergencies, including on-site fire training approved by the department and stationary fire pump engines [326 IAC 2-7-1(21)(G)(xxii)]

(aa) A warehouse identified as the Calumet Warehouse that includes the following emission sources and may also include other insignificant activities listed in Section A.4 of this permit [326 IAC 6.8-1-2(b)]:

(1) Kewanee Boiler No. 1 with a maximum design capacity of 5.5 MMBtu/hr heat input and is natural gas-fired only, venting to stack, S-1.

(2) Kewanee Boiler No. 2 with a maximum design capacity of 5.5 MMBtu/hr heat input and is natural gas-fired only, venting to stack, S-2.

(bb) Routine maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process, including the following [326 IAC 2-7-1(21)(G)(xvii)]:

(1) Purging of gas lines.

(2) Purging of vessels.

(cc) Flue gas conditioning systems and associated chemicals, such as the following [326 IAC 2-7-1(21)(G)(xviii)]:

(1) Sodium sulfate.

(2) Ammonia.

(3) Sulfur trioxide.

(dd) Purge double block and bleed valves [326 IAC 2-7-1(21)(G)(xxiv)].

(ee) Filter or coalescer media changeout [326 IAC 2-7-1(21)(G)(xxv)].

(ff) Three (3) emergency firepump engines, identified as Firepump 1, 2 and 3, per SPM 089-25488-00453, each rated at 390 HP.

(gg) One (1) concrete crushing process, per SPM 089-25488-00453, with a maximum processing capacity of 120 tons per hour, having two (2) transfer points.

A.5 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-7-1]

Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-7) shall prevail.

B.2 Permit Term [326 IAC 2-7-5(2)] [326 IAC 2-1.1-9.5] [326 IAC 2-7-4(a)(1)(D)] [IC 13-15-3-6(a)]

(a) This permit, T089-6741-00453, is issued for a fixed term of five (5) years from the effective date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit.

(b) If IDEM, OAQ, upon receiving a timely and complete renewal permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect, including any permit shield provided in 326 IAC 2-7-15, until the renewal permit has been issued or denied.

B.3 Enforceability [326 IAC 2-7-7]

(a) Unless otherwise stated, all terms and conditions in this permit, including any provisions designed to limit the source's potential to emit, are enforceable by IDEM, OAQ, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.

(b) Unless otherwise stated, all terms and conditions in this permit that are local requirements, including any provisions designed to limit the source's potential to emit, are enforceable by Hammond Department of Environmental Management.

(c) The Permittee shall take all steps necessary to maintain compliance with the nuisance provisions as specified in the City of Hammond Air Quality Control Ordinance No. 3522 (as amended), Article VI, Section 6.11 Nuisance Abatement.

B.4 Termination of Right to Operate [326 IAC 2-7-10] [326 IAC 2-7-4(a)]

The Permittee's right to operate this source terminates with the expiration of this permit unless a timely and complete renewal application is submitted at least nine (9) months prior to the date of expiration of the source’s existing permit, consistent with 326 IAC 2-7-3 and 326 IAC 2-7-4(a).

B.5 Severability [326 IAC 2-7-5(5)]

The provisions of this permit are severable; a determination that any portion of this permit is invalid shall not affect the validity of the remainder of the permit.

B.6 Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]

This permit does not convey any property rights of any sort or any exclusive privilege.

B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

(a) The Permittee shall furnish to IDEM, OAQ, and Hammond Department of Environmental Management within a reasonable time, any information that IDEM, OAQ, and Hammond Department of Environmental Management may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The submittal by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34). Upon request, the Permittee shall also furnish to IDEM, OAQ, and Hammond Department of Environmental Management copies of records required to be kept by this permit.

(b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U.S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.

B.8 Certification [326 IAC 2-7-4(f)] [326 IAC 2-7-6(1)] [326 IAC 2-7-5(3)(C)]

(a) Where specifically designated by this permit or required by an applicable requirement, any application form, report, or compliance certification submitted shall contain certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) One (1) certification shall be included, using the attached Certification Form, with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

(c) A responsible official is defined at 326 IAC 2-7-1(34).

B.9 Annual Compliance Certification [326 IAC 2-7-6(5)]

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. The initial certification shall cover the time period from the effective date of the permit through December 31 of the same year. All subsequent certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than April 15 of each year to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

Hammond Department of Environmental Management
5925 Calumet Avenue
Hammond, Indiana 46320

and

United States Environmental Protection Agency, Region V
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

(b) The annual compliance certification report required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, and Hammond Department of Environmental Management on or before the date it is due.

(c) The annual compliance certification report shall include the following:

(1) The appropriate identification of each term or condition of this permit that is the basis of the certification;

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

(4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-7-5(3); and

(5) Such other facts, as specified in Sections D of this permit, as IDEM, OAQ, and Hammond Department of Environmental Management may require to determine the compliance status of the source.

The submittal by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)] [326 IAC 2-7-6(1) and (6)] [326 IAC 1-6-3]

(a) The Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) within ninety (90) days after the effective date of this permit or prior to startup of each respective modification or new unit, whichever is later, for the source as described in 326 IAC 1-6-3. At a minimum, the PMPs shall include:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee's control, the PMPs cannot be prepared and maintained within the above time frame, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

Hammond Department of Environmental Management
5925 Calumet Avenue
Hammond, Indiana 46320

The PMP extension notification does not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) A copy of the PMPs shall be submitted to IDEM, OAQ, and Hammond Department of Environmental Management upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ, and Hammond Department of Environmental Management. IDEM, OAQ, and Hammond Department of Environmental Management may require the Permittee to revise its PMPs. The PMPs do not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation, Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for the unit.

B.11 Emergency Provisions [326 IAC 2-7-16]

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:

(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, Hammond Department of Environmental Management, the Northwest Regional Office, within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered. The Hammond Department of Environmental Management need only be notified if the emission units affected are located within the jurisdiction of the Hammond Department of Environmental Management.

<u>IDEM, OAQ:</u>
Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance Section), or
Telephone Number: 317-233-5674 (ask for Compliance Section)
Facsimile Number: 317-233-5967

<u>Hammond Department of Environmental Management:</u>
Telephone Number: 219-853-6306
Facsimile Number: 219-853-6343

<u>Northwest Regional Office:</u>
Telephone Number: 219-881-6712
Telephone Number: 888-209-8892
Facsimile Number: 219-881-6745

(5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

For emergencies within the jurisdiction of the Hammond Department of Environmental Management, the Permittee shall submit the Emergency Occurrence Report Form to:

Hammond Department of Environmental Management
5925 Calumet Avenue
Hammond, Indiana 46320

The report shall be submitted within two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and shall contain the following:

(A) A description of the emergency;

(B) Any steps taken to mitigate the emissions; and

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any emission limitation. However, IDEM, OAQ, and Hammond Department of Environmental Management may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4-(c)(9) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ, and Hammond Department of Environmental Management (for emergencies occurring within its jurisdiction) by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.

(g) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

(h) The Permittee shall include all emergencies in the Quarterly Deviation and Compliance Monitoring Report.

B.12 Permit Shield [326 IAC 2-7-15] [326 IAC 2-7-20] [326 IAC 2-7-12]

(a) Pursuant to 326 IAC 2-7-15, the Permittee has been granted a permit shield. The permit shield provides, except as otherwise specified in this Section (B.12 – Permit Shield), that compliance with the conditions of this permit shall be deemed compliance with any

applicable requirements as of the effective date of the permit, provided that either the applicable requirements are included and specifically identified in this permit or the permit contains an explicit determination or concise summary of a determination that other specifically identified requirements are not applicable. The Indiana statutes from IC 13 and rules from 326 IAC, referenced in conditions in this permit, are those applicable at the time the permit was issued. The issuance or possession of this permit shall not alone constitute a defense against an alleged violation of any law, regulation or standard, except for the requirement to obtain a Part 70 permit under 326 IAC 2-7 or for applicable requirements for which a permit shield has been granted.

This permit shield does not extend to applicable requirements which are promulgated after the date of issuance of this permit unless this permit has been modified to reflect such new requirements.

(b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ, shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.

(c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.

(d) Nothing in 326 IAC 2-7-15 or in this permit shall alter or affect the following:

(1) The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the U.S. EPA under Section 303 of the Clean Air Act;

(2) The liability of the Permittee for any violation of applicable requirements prior to or at the time of the effective date of this permit;

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; and

(4) The ability of U.S. EPA to obtain information from the Permittee under Section 114 of the Clean Air Act.

(e) This permit shield is not applicable to any change made under 326 IAC 2-7-20(b)(2) (Sections 502(b)(10) of the Clean Air Act changes) and 326 IAC 2-7-20(c)(2) (trading based on State Implementation Plan (SIP) provisions).

(f) This permit shield is not applicable to modifications eligible for group processing until after IDEM, OAQ, has issued the modifications. [326 IAC 2-7-12(c)(7)]

(g) This permit shield is not applicable to minor Part 70 permit modifications until after IDEM has issued the modification. [326 IAC 2-7-12(b)(8)]

(h) On January 25, 2007 and November 29, 2007 the U.S. EPA issued Notices of Violation (NOV) to the Permittee for allegedly failing to comply with the provisions set out in 326 IAC 2 and the Clean Air Act, including the Prevention of Significant Deterioration and the nonattainment New Source Review programs, the federal New Source Performance Standards (NSPS), and the National Emission Standards for Hazardous Air Pollutants. In

addition, the Notices of Violation issued by U.S.EPA allege violations of the Consent Decree between the United States, et al., and BP entered on August 29, 2001, and amendments thereto. Therefore the Permit Shield in Section B - Permit Shield does not shield the Permittee from possible enforcement actions initiated by U.S. EPA, IDEM or citizens. Compliance with the terms of this permit does not serve as proof of compliance for the emission units or the matters addressed in the NOVs. Following resolution of this enforcement action, IDEM will reopen this permit, if necessary, to incorporate a compliance schedule or any new applicable requirements. The standard language of Section B - Permit Shield does not shield any activity on which the permit is silent.

B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5] [326 IAC 2-7-10.5]

(a) All terms and conditions of permits established prior to T089-6741-00453, and issued pursuant to permitting programs approved into the state implementation plan have been either

(1) incorporated as originally stated,

(2) revised under 326 IAC 2-7-10.5, or

(3) deleted under 326 IAC 2-7-10.5.

(b) Provided that all terms and conditions are accurately reflected in this combined permit, all previous registrations and permits are superseded by this Part 70 operating permit.

B.14 Deviations from Permit Requirements and Conditions [326 IAC 2-7-5(3)(C)(ii)]

(a) Deviations from any permit requirements (for emergencies see Section B - Emergency Provisions), the probable cause of such deviations, and any response steps or preventive measures taken shall be reported to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and, for facilities located within the jurisdiction of the Hammond Department of Environmental Management, to

Hammond Department of Environmental Management
5925 Calumet Avenue
Hammond, Indiana 46320

using the attached Quarterly Deviation and Compliance Monitoring Report, or its equivalent. A deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report.

The Quarterly Deviation and Compliance Monitoring Report does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(b) A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

B.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)] [326 IAC 2-7-8(a)] [326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ, determines any of the following:

(1) That this permit contains a material mistake.

(2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.

(3) That this permit shall be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]

(c) Proceedings by IDEM, OAQ, to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]

(d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ, at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ, may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

B.16 Permit Renewal [326 IAC 2-7-4] [326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ, and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

(b) A timely renewal application is one that is:

(1) Submitted at least nine (9) months prior to the date of the expiration of this permit; and

(2) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, on or before the date it is due.

(c) If the Permittee submits a timely and complete application for renewal of this permit, the source's failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ, takes final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by the deadline specified in writing by IDEM, OAQ, any additional information identified as being needed to process the application.

B.17 Permit Amendment or Modification [326 IAC 2-7-11] [326 IAC 2-7-12]

(a) Permit amendments and modifications are governed by the requirements of 326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify this permit.

(b) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application shall be certified by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.18 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)] [326 IAC 2-7-12 (b)(2)]

(a) No Part 70 permit revision shall be required under any approved economic incentives, marketable Part 70 permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 permit.

(b) Notwithstanding 326 IAC 2-7-12(b)(1) and 326 IAC 2-7-12(c)(1), minor Part 70 permit modification procedures may be used for Part 70 modifications involving the use of economic incentives, marketable Part 70 permits, emissions trading, and other similar approaches to the extent that such minor Part 70 permit modification procedures are explicitly provided for in the applicable State Implementation Plan (SIP) or in applicable requirements promulgated or approved by the U.S. EPA.

B.19 Operational Flexibility [326 IAC 2-7-20] [326 IAC 2-7-10.5]

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b), (c), or (e), without a prior permit revision, if each of the following conditions is met:

(1) The changes are not modifications under any provision of Title I of the Clean Air Act;

(2) Any preconstruction approval required by 326 IAC 2-7-10.5 has been obtained;

(3) The changes do not result in emissions which exceed the limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

(4) The Permittee notifies the:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region V
Air and Radiation Division, Regulation Development Branch -
Indiana (AR-18J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

and, for facilities located within the jurisdiction of the Hammond Department of Environmental Management,

Hammond Department of Environmental Management
5925 Calumet Avenue
Hammond, Indiana 46320

in advance of the change by written notification at least ten (10) days in advance of the proposed change. The Permittee shall attach every such notice to the Permittee's copy of this permit; and

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emissions trading that are subject to 326 IAC 2-7-20(b), (c), or (e). The Permittee shall make such records available, upon reasonable request, for public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ, and Hammond Department of Environmental Management in the notices specified in 326 IAC 2-7-20(b)(1), (c)(1), and (e)(2).

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(36)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

(1) A brief description of the change within the source;

(2) The date on which the change will occur;

(3) Any change in emissions; and

(4) Any permit term or condition that is no longer applicable as a result of the change.

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(c) Emission Trades [326 IAC 2-7-20(c)]
The Permittee may trade emissions increases and decreases at the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-7-20(c). The notification requirement in (a)(4) of this condition does not apply to emission trades of SO_2 or NO_x under 326 IAC 10-4.

(d) Alternative Operating Scenarios [326 IAC 2-7-20(d)]
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ, or U.S. EPA is required.

(e) Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.

(f) This condition does not apply to emission trades of NO_x under 326 IAC 10-4.

B.20 Source Modification Requirement [326 IAC 2-7-10.5] [326 IAC 2-2] [326 IAC 2-3-2]

(a) A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2 and 326 IAC 2-7-10.5.

(b) Any modification at an existing major source is governed by the requirements of 326 IAC 2-2-2 and 326 IAC 2-3-2.

B.21 Inspection and Entry [326 IAC 2-7-6] [IC 13-14-2-2] [IC 13-30-3-1] [IC 13-17-3-2]

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, and Hammond Department of Environmental Management U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a Part 70 source is located, or emissions related activity is conducted, or where records shall be kept under the conditions of this permit;

(b) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, have access to and copy any records that shall be kept under the conditions of this permit;

(c) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

(d) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, sample or monitor substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

(a) The Permittee shall comply with the requirements of 326 IAC 2-7-11 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.

(b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and a copy of the application shall be submitted to

Hammond Department of Environmental Management
5925 Calumet Avenue
Hammond, Indiana 46320

The application which shall be submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)] [326 IAC 2-1.1-7]

(a) The Permittee shall pay annual fees to IDEM, OAQ, thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ, applicable fee is due April 1 of each year.

(b) Except as provided in 326 IAC 2-7-19(e), failure to pay may result in administrative enforcement action or revocation of this permit.

(c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-4230 (ask for OAQ, Billing, Licensing, and Training Section (BLT)), to determine the appropriate permit fee.

B.24 Term of Conditions [326 IAC 2-1.1-9.5]

Notwithstanding the permit term of a permit to construct, a permit to operate, or a permit modification, any conditions established in a permit issued, pursuant to a permitting program approved in the state implementation plan shall remain in effect until:

(a) the condition is modified in a subsequent permit action pursuant to Title I of the Clean Air Act; or

(b) the emission unit to which the condition pertains permanently ceases operation.

B.25 Credible Evidence [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [62 FR 8314] [326 IAC 1-1-6]

For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any condition of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to

whether the Permittee would have been in compliance with the condition of this permit if the appropriate performance or compliance test or procedure had been performed.

SECTION C **SOURCE OPERATION CONDITIONS**

Entire Source

Emission Limitations and Standards [326 IAC 2-7-5(1)]

C.1 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of twenty percent (20%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.2 Open Burning [326 IAC 4-1] [IC 13-17-9]

The Permittee shall not open burn any material except as provided in 326 IAC 4-1-3, 326 IAC 4-1-4 or 326 IAC 4-1-6. The previous sentence notwithstanding, the Permittee may open burn in accordance with an open burning approval issued by the Commissioner under 326 IAC 4-1-4.1. 326 IAC 4-1-3 (a)(2)(A) and (B) are federally enforceable.

C.3 Incineration [326 IAC 4-2] [326 IAC 9-1-2]

The Permittee shall not operate an incinerator or incinerate any waste or refuse except as provided in 326 IAC 4-2 and 326 IAC 9-1-2.

C.4 Fugitive Dust Emissions [326 IAC 6-4]

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

C.5 Fugitive Dust Emissions [326 IAC 6.8-10-3]

Pursuant to 326 IAC 6.8-10-3 (Lake County Fugitive Particulate Matter Control Requirements), the particulate matter emissions from source wide activities shall meet the following requirements:

(a) The average instantaneous opacity of fugitive particulate emissions from a paved road shall not exceed ten percent (10%), as determined in accordance with the procedures specified in 326 IAC 6.8-10-3(1).

(b) The average instantaneous opacity of fugitive particulate emissions from an unpaved road shall not exceed ten percent (10%), as determined in accordance with the procedures specified in 326 IAC 6.8-10-3(2).

(c) The average instantaneous opacity of fugitive particulate emissions from batch transfer shall not exceed ten percent (10%), as determined in accordance with the procedures specified in 326 IAC 6.8-10-3(3)(A).

(d) The opacity of fugitive particulate emissions from storage piles shall not exceed ten percent (10%) on a six (6) minute average, as determined in accordance with the procedures specified in 326 IAC 6.8-10-3(5).

(e) There shall be a zero (0) percent frequency of visible emission observations of a material during the inplant transportation of material by truck or rail at any time, as determined in accordance with the procedures specified in 326 IAC 6.8-10-3(6)(A).

(f) The opacity of fugitive particulate emissions from the in plant transportation of material by front end loaders and skip hoists shall not exceed ten percent (10%), as determined in accordance with the procedures specified in 326 IAC 6.8-10-3(6)(B).

(g) There shall be a zero (0) percent frequency of visible emission observations from a building enclosing all or part of the material processing equipment, except from a vent in the building, as determined in accordance with the procedures specified in 326 IAC 6.8-10-3(7)(D).

(h) The PM10 emissions from building vents shall not exceed twenty-two thousandths (0.022) grains per dry standard cubic foot and ten percent (10%) opacity, as determined in accordance with the procedures specified in 326 IAC 6.8-10-3(7)(E).

(i) The opacity of particulate emissions from dust handling equipment shall not exceed ten percent (10%), as determined in accordance with the procedures specified in 326 IAC 6.8-10-3(8).

(j) Any facility or operation not specified in 326 IAC 6.8-10-3 shall meet a twenty percent (20%), three (3) minute average opacity standard, as determined in accordance with the procedures specified in 326 IAC 6.8-10-3(9).

The Permittee shall achieve these limits by controlling fugitive particulate matter emissions according to the Fugitive Dust Control Plan, submitted on December 11, 1993, revised on May 28, 2004, and included in Appendix A.

C.6 Stack Height [326 IAC 1-7]

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted.

C.7 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

(a) Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at least 260 linear feet on pipes or 160 square feet on other facility components, or at least thirty-five (35) cubic feet on all facility components, then the notification requirements of 326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.

(b) The Permittee shall ensure that a written notification is sent on a form provided by the Commissioner at least ten (10) working days before asbestos stripping or removal work or before demolition begins, per 326 IAC 14-10-3, and shall update such notice as necessary, including, but not limited to the following:

(1) When the amount of affected asbestos containing material increases or decreases by at least twenty percent (20%); or

(2) If there is a change in the following:

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

(c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3(2).

(d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3(3).

All required notifications shall be submitted to:

Indiana Department of Environmental Management
Asbestos Section, Office of Air Quality
100 North Senate Avenue
MC 61-52 IGCN 1003
Indianapolis, Indiana 46204-2251

and, for facilities located within the jurisdiction of the Hammond Department of Environmental Management, to

Hammond Department of Environmental Management
5925 Calumet Avenue
Hammond, Indiana 46320

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(e) Procedures for Asbestos Emission Control
The Permittee shall comply with the applicable emission control procedures in 326 IAC 14-10-4 and 40 CFR 61.145(c). Per 326 IAC 14-10-4-1, emission control requirements are applicable for any removal or disturbance of RACM greater than three (3) linear feet on pipes or three (3) square feet on any other facility components or a total of at least 0.75 cubic feet on all facility components.

(f) Demolition and Renovation
The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).

(g) Indiana Accredited Asbestos Inspector
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Accredited Asbestos Inspector to thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Accredited Asbestos inspector is not federally enforceable.

Testing Requirements [326 IAC 2-7-6(1)]

C.8 Performance Testing [326 IAC 3-6]

(a) All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.

A test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) Pursuant to 326 IAC 3-6-4(b), all test reports shall be received by IDEM, OAQ, and not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ, if the source submits to IDEM, OAQ, a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period.

Compliance Requirements [326 IAC 2-1.1-11]

C.9 Compliance Requirements [326 IAC 2-1.1-11]

The commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with all applicable requirements by issuing an order under 326 IAC 2-1.1-11. Any monitoring or testing shall be performed in accordance with 326 IAC 3 or other methods approved by the commissioner or the U.S. EPA.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)] [326 IAC 2-7-6(1)]

C.10 Compliance Monitoring [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

Unless otherwise specified in this permit, all monitoring and record keeping requirements not already legally required shall be implemented within sixty (60) days of the effective date of the permit. If required by Section D, the Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. If due to circumstances beyond its control, that equipment cannot be installed and operated within sixty (60) days, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and, for facilities located within the jurisdiction of the Hammond Department of Environmental Management, to

Hammond Department of Environmental Management
5925 Calumet Avenue
Hammond, Indiana 46320

in writing, prior to the end of the initial sixty (60) day compliance schedule, with full justification of the reasons for the inability to meet this date.

The notification which shall be submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.

C.11 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment, as required in Sections D or E of this permit. For a boiler, the COMS shall be in operation at all times that the induced draft fan is in operation.

(b) All COMS shall meet the performance specifications of 40 CFR 60, Appendix B, Performance Specification No. 1, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5.

(c) In the event that a breakdown of a COMS occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(d) Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the emissions from the emission unit stack.

(1) Visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not more than twenty-four (24) hours after the start of the malfunction or down time.

(2) Method 9 opacity readings shall be repeated for a minimum of five (5) consecutive six (6) minute averaging periods at least twice per day during daylight operations, with at least four (4) hours between each set of readings, until a COMS is online.

(3) Method 9 readings may be discontinued once a COMS is online.

(4) Any opacity exceedances determined by Method 9 readings shall be reported with the Quarterly Opacity Exceedances Reports.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous opacity monitoring system pursuant to 326 IAC 3-5, and 326 IAC 6.8-1).

C.12 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment, as required in Sections D or E of this permit.

(b) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(c) Whenever a H_2S continuous emission monitoring system is malfunctioning or will be down for calibration, maintenance, or repairs for more than twenty-four (24), the Permittee shall

measure and record Draeger tube sampling of the fuel gas one time per hour until the primary CEMS or a backup CEMS is brought online.

(d) Whenever the SO_2 continuous emission monitoring system on the FCU 500 or FCU 600 is malfunctioning or will be down for calibration, maintenance, or repairs for more than twenty-four (24) hours, the Permittee shall monitor and record unit feed rate, feed sulfur analysis and SO_x additive injection rate to demonstrate that the operation of the unit continues in a typical manner. These parametric monitoring readings shall be recorded at least once per day until the primary CEM or backup CEM is brought online.

(e) Whenever the NO_x continuous emission monitoring system on the FCU 500 or FCU 600 is malfunctioning or will be down for calibration, maintenance, or repairs for more than twenty-four (24) hours, the Permittee shall monitor and record unit feed rate, ammonia injection rates and regenerator bed temperature to demonstrate that the operation of the unit continues in a typical manner. These parametric monitoring readings shall be recorded at least once per day until the primary CEM or backup CEM is brought online.

(f) Whenever the CO continuous emission monitoring system on the FCU 500 or FCU 600 is malfunctioning or will be down for calibration, maintenance, or repairs for more than twenty-four (24) hours, the Permittee shall monitor and record unit feed rate, regenerator bed temperature and percent excess oxygen via the regenerator process analyzer to demonstrate that the operation of the unit continues in a typical manner. These parametric monitoring readings shall be recorded at least once per day until the primary CEM or backup CEM is brought online.

(g) Whenever the SO_2 continuous emission monitoring system on the SBS TGU is malfunctioning or will be down for calibration, maintenance, or repairs for more than twenty-four (24) hours, the Permittee shall monitor and record outlet furnace temperatures, SBS product pH and density, and SBS product flow rate to demonstrate that the operation of the unit continues in a typical manner. These parametric monitoring readings shall be recorded at least once per day until the primary CEM or backup CEM is brought online.

(h) Whenever the TRS continuous emission monitoring system on the B/S TGU is malfunctioning or will be down for calibration, maintenance, or repairs for more than twenty-four (24) hours, the Permittee shall monitor and record the inlet temperature to the hydrogenation reactor and the flow rate of Stretford solution to the venture scrubbers to demonstrate that the operation of the unit continues in a typical manner. The TGU combustor will be operated during this period. These parametric monitoring readings shall be recorded at least once per day until the primary CEM or backup CEM is brought online.

(i) Whenever the CO continuous emission monitoring system on the FBI is malfunctioning or will be down for calibration, maintenance, or repairs for more than twenty-four (24) hours, the Permittee shall remove the hazardous waste feed stream to the FBI until the primary CEM or backup CEM is brought online.

(j) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 40 CFR 63, Subpart EEE for the Fluidized Bed Incinerator, 40 CFR 60, Subpart J for affected process heaters, boilers, and flares, and 40 CFR 63, Subpart UUU for SBS TGU, B/S TGU, FCU 500 and FCU 600.

C.13 Maintenance of Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) In the event that a breakdown of the emission monitoring equipment occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the

problem. To the extent practicable, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less frequent than required in Section D of this permit until such time as the monitoring equipment is back in operation. In the case of continuous monitoring, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less often than once an hour until such time as the continuous monitor is back in operation.

(b) The Permittee shall install, calibrate, quality assure, maintain, and operate all necessary monitors and related equipment.

C.14 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]

Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, 40 CFR 60 Appendix B, 40 CFR 63, or other approved methods as specified in this permit.

C.15 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

(a) When required by any condition of this permit, an analog instrument used to measure a parameter related to the operation of an air pollution control device shall have a scale such that the expected maximum reading for the normal range shall have a scale such that the expected normal reading shall be no less than twenty percent (20%) of full scale.

(b) The Permittee may request that the IDEM, OAQ approve the use of an instrument that does not meet the above specifications provided the Permittee can demonstrate that an alternative pressure gauge or other instrument specification will adequately ensure compliance with permit conditions requiring the measurement of the parameters.

Corrective Actions and Response Steps [326 IAC 2-7-5] [326 IAC 2-7-6]

C.16 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall prepare written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) These ERPs shall be submitted for approval to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

Hammond Department of Environmental Management
5925 Calumet Avenue
Hammond, Indiana 46320

within ninety (90) days after the effective date of this permit.

The ERP does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(c) If the ERP is disapproved by IDEM, OAQ, and Hammond Department of Environmental Management, the Permittee shall have an additional thirty (30) days to resolve the differences and submit an approvable ERP.

(d) These ERPs shall state those actions that will be taken, when each episode level is declared, to reduce or eliminate emissions of the appropriate air pollutants.

(e) Said ERPs shall also identify the sources of air pollutants, the approximate amount of reduction of the pollutants, and a brief description of the manner in which the reduction will be achieved.

(f) Upon direct notification by IDEM, OAQ, and Hammond Department of Environmental Management, that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

C.17 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68]

If a regulated substance as defined in 40 CFR 68 is present at a source in more than a threshold quantity, the Permittee shall comply with the applicable requirements of 40 CFR 68.

C.18 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) Upon detecting an excursion or exceedance, the Permittee shall restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Corrective actions may include, but are not limited to, the following:

(1) initial inspection and evaluation;

(2) recording that operations returned to normal without operator action (such as through response by a computerized distribution control system); or

(3) any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not limited to, the following:

(1) monitoring results;

(2) review of operation and maintenance procedures and records;

(3) inspection of the control device, associated capture system, and the process.

(d) Failure to take reasonable response steps shall be considered a deviation from the permit.

(e) The Permittee shall maintain the following records:

(1) monitoring data;

(2) monitor performance data, if applicable; and

(3) corrective actions taken.

(f) For the purposes of this Condition:

(1) "Exceedance" shall mean a condition that is detected by monitoring that provides data in terms of an emission limitation or standard and that indicates that emissions are, or opacity is, greater than the applicable emission limitation or standard (or less than the applicable standard in the case of a percent reduction requirement), consistent with any averaging period specified for averaging the results of the monitoring.

(2) "Excursion" shall mean a departure from an indicator range established for monitoring under Section D of this permit, consistent with any averaging period specified for averaging the results of the monitoring.

C.19 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate response actions. The Permittee shall submit a description of these response actions to IDEM, OAQ, within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize excess emissions from the affected facility while the response actions are being implemented.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one-hundred and twenty (120) days is not practicable, IDEM, OAQ may extend the retesting deadline.

(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The response action documents submitted pursuant to this condition do require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

C.20 Emission Statement [326 IAC 2-7-5(3)(C)(iii)] [326 IAC 2-7-5(7)] [326 IAC 2-7-19(c)] [326 IAC 2-6]

(a) Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit by July 1 an annual emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

(1) Indicate estimated actual emissions of all pollutants listed in 326 IAC 2-6-4(a);

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(32) ("Regulated pollutant, which is used only for purposes of Section 19 of this rule") from the source, for purposes of fee assessment.

The emission statement shall be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue
MC 61-50 IGCN 1003
Indianapolis, Indiana 46204-2251

and, for facilities located with the jurisdiction of the Hammond Department of Environmental Management, to

Hammond Department of Environmental Management
5925 Calumet Avenue
Hammond, Indiana 46320

The emission statement does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The annual emission statement required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, and Hammond Department of Environmental Management, on or before the date it is due.

C.21 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2] [326 IAC 2-3]

(a) Records of all required monitoring data, reports and support information required by this Permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner or the Hammond Department of Environmental Management, makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner or the Hammond Department of Environmental Management, within a reasonable time.

(b) Unless otherwise specified in this permit, all record keeping requirements not already legally required shall be implemented within ninety (90) days of the effective date of this permit.

(c) If there is a reasonable possibility that a "project" (as defined in 326 IAC 2-2-1(qq) or 326 IAC 2-3-1(ll)) at a major source other than projects at a source with a Plantwide Appliacbility Limitation (PAL) which is not part of a "major Modification" (as defined in 326 IAC 2-2-1(ee) or 326 IAC 2-3-1(z)) and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(rr) or 326 IAC 2-3-1(mm), the Permittee shall comply with the following:

(1) Prior to commencing the construction of "project" (as defined in 326 IAC 2-2-1(qq) or 326 IAC 2-3-1(ll)) document and maintain the following records:

(A) A description of the project;

(B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project;

(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:

(i) Baseline actual emissions;

(ii) Projected actual emissions;

(iii) Amount of emissions excluded under section 326 IAC 2-2-1(rr)(2)(A)(iii) or 326 IAC 2-3-1(mm)(2)(A)(iii); and

(iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.

(2) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in (1)(B) above; and

(3) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) ten years following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emission unit.

C.22 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2] [326 IAC 2-3]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken shall be reported. This report shall be submitted within thirty (30) days of the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(b) The report required in (a) of this condition and reports required by conditions in Section D of this permit shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and, for facilities located with the jurisdiction of the Hammond Department of Environmental Management, to

Hammond Department of Environmental Management
5925 Calumet Avenue
Hammond, Indiana 46320

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, and Hammond Department of Environmental Management, on or before the date it is due.

(d) Unless otherwise specified in this permit, all reports required in Section D of this permit shall be submitted within thirty (30) days of the end of the reporting period. All reports do require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(e) The first report shall cover the period commencing on the effective date of this permit and ending on the last day of the reporting period. Reporting periods are based on calendar

years, unless otherwise specified in this permit. For the purpose of this permit "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

(f) If the Permittee is required to comply with the recordkeeping provisions of (c) in Section C – General Record Keeping Requirements for any "project" (as defined in 326 IAC 2-2-1(qq) or 326 IAC 2-3-1(ll)), and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:

(1) The annual emission, in tons per year, form the project identified in (c)(1) in Section C - General Record Keeping Requirements exceed the baseline actual emissions, as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in 326 IAC 2-2-1(xx) or 326 IAC 2-3-1(qq), for that regulated NSR pollutant, and;

(2) The emissions differ from the preconstruction projection as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(ii).

(g) The report shall be submitted within sixty (60) days after the end of the year and contain the following:

(1) The name, address, and telephone number of the major stationary source.

(2) The annual emissions calculated in accordance with (c)(2) and (3) in Section C - General Record Keeping Requirements.

(3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) or 326 IAC2-3-2(c)(3).

(4) Any other information that the Permittee deems fit to include in this report.

Reports required in this part shall be submitted to:

Indiana Department of Environmental Management
Air Compliance Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

(h) The Permittee shall make the information required to be documented and maintained in accordance with (c) in Section C - General Record Keeping Requirements available for review upon a request for inspection by IDEM, OAQ. The general public may request this information from the IDEM, OAQ under 326 IAC 17.1

Stratospheric Ozone Protection

C.23 Compliance with 40 CFR 82 and 326 IAC 22-1

Pursuant to 40 CFR 82 (Protection of Stratospheric Ozone), Subpart F, except as provided for motor vehicle air conditioners in Subpart B, the Permittee shall comply with the standards for recycling and emissions reduction:

(a) Persons opening appliances for maintenance, service, repair, or disposal shall comply with the required practices pursuant to 40 CFR 82.156.

(b) Equipment used during the maintenance, service, repair, or disposal of appliances shall comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

(c) Persons performing maintenance, service, repair, or disposal of appliances shall be certified by an approved technician certification program pursuant to 40 CFR 82.161.

C.24 Consent Decree Requirements

On January 18, 2001, the Permittee entered into a Consent Decree 2:96CV 095RL to resolve alleged past violation issues at this source (referred to in the Consent Decree as the “Whiting Facility”) and seven other refineries located in California, North Dakota, Ohio, Utah, Texas, Washington, and Virginia. Pursuant to the consent decree, the Permittee shall incorporate the emission limits and schedules set out in Paragraphs 14-18 and 21 of the consent decree into minor or major new source review permits or other permits (other than the Part 70 Operating permit). Upon issuance of such permits, the Permittee shall incorporate such requirements of those permits into the Permittee's Part 70 Operating permit. Those requirements of the consent decree which have been permitted through new source review requirements by IDEM, OAQ have been incorporated into this Part 70 Operating permit under the appropriate D-sections. All requirements which have not been permitted through new source requirements as of this date, shall be incorporated into the Part 70 operating permit at a later date.

SECTION D.0 FACILITY OPERATION CONDITIONS - CXHO Project

Facility Description [326 IAC 2-7-5(15)]

Emissions units - new, modified and affected by CXHO project, including the following:

New Process Heaters
DHT B-601A
GOHT F-901A and F-901B
12 PS H-101A, H-101B and H-102
New Coker (#2 Coker) H-201, H-202, and H-203
New Hydrogen Unit HU-1 and HU-2

Modified Process Heaters
11C PS H-200
BOU F-401
ISOM H-1

Affected Process Heaters
11A PS H-1X, H-2, H-3
11C PS H-300
4UF F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, F-8B
ARU F-200A, F-200B
CFHU F-801A, F-801B, F-801C
CRU F-101, F-102
DDU WB-301, WB-302
HU B-501

Cooling Towers
Existing (affected) Cooling Towers 2, 3, 4
New Cooling Tower 7
New Cooling Tower 8
New HU Cooling Tower

SRU
New Claus Offgas Treaters (COTs) 1 and 2

New Flares
GOHT Flare
South Flare
HU Flare

Fugitive emission components from new units
DHT
GOHT
12 PS
#2 Coker
SRU
OSBL
HU

New Storage Tanks
TK-6255
TK-SH-1 and TK-SH-2
TK-5052

Brine Treatment System

TK-105A (Off spec tank 1)
TK-105B (Off spec tank 2)
TK-101 (Separation tank 1)
TK-102 (Separation tank 2)
TK-103 (Separation tank 3)
TK-104A (Sludge holding tank 1)
TK-104B (Sludge holding tank 2)

Fluidized Catalytic Cracking Units
FCU 500
FCU 600

Other Miscellaneous Units
Marine Dock
VRU 400
Fugitive dust from new Coker (#2 Coker) coke handling
Pumps in Heavy Liquid Service
Leaks from process equipment, including compressors, pumps, valves, process drains and pressure relief devices.

Unrelated Emissions units - new, modified and affected future contemporaneous to CXHO project:

New Storage Tanks
TK-3637
BT-002
Tank 8a

New Boiler 1 and New Boiler 2
Five (5) duct burners at 3 SPS
Dewatering and thermal desorption process
Three (3) emergency firepumps
11A WARP
11C WARP
FCU 500 WARP
FCU 600 WARP
FCU 600 TAR
VRU 100/200 WARP

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.0.1 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

(a) Following the issuance of SPM 089-25488-00453 the Permittee shall determine, on a monthly basis, the increase in emissions of SO2, NOx, PM, PM 10, CO, Pb, Be, Hg, H2SO4, and VOC from all new, modified and existing affected emission units at this source, and shall demonstrate, that the net emissions increases from this source remain below significant levels per twelve (12) consecutive month period beginning with issuance of SPM 089-25488-00453, in accordance with the following:

Following the issuance of SPM 089-25488-00453, and until the startup of the New Coker (#2 Coker) and associated coke handling facilities, the net emissions increases or decreases from the CXHO project, including fugitive emissions, shall be determined each month as follows:

Etotal = Emissions increases from new, modified, and affected emissions units during the past 12 month period
+ emissions increases from non-CXHO related projects during the past 12 month period
- creditable emissions decreases from CXHO related changes and creditable emissions decreases from non-CXHO related projects during the past 12 month period
+ emissions from creditable past contemporaneous increases
– emissions from creditable past contemporaneous decreases.

(b) Emissions from Boilers and Process Heaters shall be calculated as follows:

(1) Emissions increases each month from the existing modified and affected process heaters and boilers not equipped with a CEMS shall be calculated as follows based on the emission factors in Table D.0.1 or a more representative emission factors as verified through source testing per Condition D.0.3:

E = (Actual Heat Input - Baseline Heat Input) (mmBTU) x Emission Factor (lb/mmBTU)

$$Emissions\left(\frac{ton}{mo}\right) = \left((HI_A * EF_A) - (HI_B * EF_B)\right) * \frac{1\,ton}{2{,}000\,lb}$$

Where,

HI_A = Actual Heat Input (mmBtu/mo)
HI_B = Baseline heat input (mmBTU/mo)

EF_A = Actual emission factor (lb/mmBTU)
EF_B = Baseline emission factor (lb/mmBTU).

Table D.0.1 Emission Factors in lb/mmBTU					
Process Unit	VOC	NOx	CO	PM	PM10/PM2.5
11A PS					
H-1X	0.0054	0.166	0.082	0.0019	0.0075
H-2	0.0054	0.098	0.082	0.0019	0.0075
H-3	0.0054	0.098	0.082	0.0019	0.0075
11C PS					
H-200	0.0054	0.275*	0.082	0.0019	0.0075
H-300	0.0054	0.137	0.082	0.0019	0.0075
New #2 Coker					
H-201	0.0054	0.02	0.019	0.0019	0.0081***
H-202	0.0054	0.02	0.019	0.0019	0.0081***
H-203	0.0054	0.02	0.019	0.0019	0.0081***
12 PS					
H-101A	0.0054	0.05	0.019	0.0019	0.0075
H-102	0.0054	0.05	0.019	0.0019	0.0075
H-101B	0.0054	0.05	0.019	0.0019	0.0075
4UF					

Table D.0.1 Emission Factors in lb/mmBTU					
Process Unit	VOC	NOx	CO	PM	PM10/PM2.5
F-1	0.0054	0.098	0.082	0.0019	0.0075
F-8A	0.0054	0.275	0.082	0.0019	0.0075
F-8B	0.0054	0.275	0.082	0.0019	0.0075
F-2	0.0054	0.186	0.082	0.0019	0.0075
F-3	0.0054	0.275	0.082	0.0019	0.0075
F-4	0.0054	0.275	0.082	0.0019	0.0075
F-5	0.0054	0.098	0.082	0.0019	0.0075
F-6	0.0054	0.098	0.082	0.0019	0.0075
F-7	0.0054	0.098	0.082	0.0019	0.0075
ARU					
F-200A	0.0054	0.275	0.082	0.0019	0.0075
F-200B	0.0054	0.275	0.082	0.0019	0.0075
BOU					
F-401	0.0054	0.098	0.082	0.0019	0.0075
CFHU					
F-801A	0.0054	0.049	0.082	0.0019	0.0075
F-801B	0.0054	0.049	0.082	0.0019	0.0075
F-801C	0.0054	0.036	0.0001	0.0019	0.0075
GOHT					
F-901A	0.0054	0.04	0.02	0.0019	0.0075
F-901B	0.0054	0.04	0.02	0.0019	0.0075
CRU					
F-101	0.0054	0.080	0.082	0.0019	0.0075
F-102	0.0054	0.080	0.082	0.0019	0.0075
DDU					
WB-301	0.0054	0.035	0.04	0.0019	0.0075
WB-302	0.0054	0.030	0.04	0.0019	0.0075
DHT					
B-601/B-601A	0.0054	0.040	0.04	0.0019	0.0075
ISOM					
H-1	0.0054	0.275	0.082	0.0019	0.0075
HU					
B-501	0.0054	0.068	0.02	0.0019	0.0075
New HU (3rd Party SMR)					
HU-1	0.0034	0.013	0.015	0.0068	0.0068***
HU-2	0.0034	0.013	0.015	0.0068	0.0068***
3 SPS Boilers 1, 2, 3, 4, 6 Duct Burners for SCRs	0.0054	0.02	**	0.0019	0.0087***

* This factor will be 0.05 lb/mmBTU following installation of low NOx burners.
** CO emissions will be measured using a CO analyzer.
*** Includes PM_{10}/PM2.5 generated from SCR

(3) Emissions increases of SO_2 shall be calculated as follows:

$$SO_2\ Emissions\left(\frac{ton}{mo}\right)=\left(D_A * SO_2\ EF_A * \frac{1}{HHV_A} - D_B * SO_2\ EF_B * \frac{1}{HHV_B}\right) * \frac{1\,ton}{2{,}000\,lb}$$

Where,

D_A = Actual Heat Input (mmBtu/mo)
D_B = Baseline heat input (mmBTU/mo)
HHV_A = Actual Fuel gas higher heating value (mmBtu/mmcf)
HHV_B = Baseline Fuel gas higher heating value (mmBtu/mmcf)
SO_2 EF_A = Actual SO_2 emission factor (lb/mmcf)
SO_2 EF_B = Baseline SO_2 emission factor (lb/mmcf).

The SO_2 emission factor is a function of the total sulfur concentration in the fuel gas and is calculated from the Ideal Gas Law as follows:

$$SO_2\ EF = \frac{C * MW * P}{R * T}$$

Where,

C = Fuel gas total sulfur concentration (ppm)
MW = Molecular Weight (lb/lbmol)
P = Pressure (psia)
R = Ideal Gas Constant (psia*ft3/(lbmol*R))
T = Temperature (R)

Until total sulfur monitors are installed on the fuel gas system, total sulfur in the fuel gas shall be determined as follows:
Total sulfur (ppm) = H_2S (ppm) + Mercaptan (ppm)
Where,
H_2S (ppm) = concentration of H_2S in fuel gas as measured by existing fuel continuous H_2S analyzers.
Mercaptan (ppm) = 111 ppm (or a revised average concentration based on sampled data)

(c) Emissions increases from FCU 500 and FCU 600 shall be calculated as follows:

(A) SO_2, NO_x, and CO emissions increases or decreases (actual emissions for that month - baseline emissions) shall be calculated from CEMS data collected at the FCU 500 and FCU 600 exhaust stacks using the following formulas:

$$\text{Emissions}\left(\frac{\text{ton}}{\text{mo}}\right)=\left[C_A * \text{coke}_A * \left(11.6\frac{\text{lb Exhaust Gas}}{\text{lb coke}}\right)\left(\frac{\text{MW Pollutant}}{\text{MW Exhaust Gas}}\right) * \frac{1\text{ ton}}{2{,}000\text{ lb}}\right] -$$

$$\left[C_B * \text{coke}_B * \left(11.6\frac{\text{lb Exhaust Gas}}{\text{lb coke}}\right)\left(\frac{\text{MW Pollutant}}{\text{MW Exhaust Gas}}\right) * \frac{1\text{ ton}}{2{,}000\text{ lb}}\right]$$

Where,

C_A = Actual Pollutant concentration (ppm) at 0% excess oxygen

$Coke_A$ = Actual Total coke burned (lb/mo)

C_B = Baseline Pollutant concentration (ppm) at 0% excess oxygen

$Coke_B$ = Baseline Total coke burned (lb/mo)

Ratio of Exhaust Gas (lb):coke (lb) = 11.6 per refinery engineering estimates

(B) VOC and PM/PM_{10}/$PM_{2.5}$ emissions increases or decreases (actual emissions - baseline emissions) shall be calculated based on the increase in the amount of feed to the unit and the calculated coke burn rate combined with the following emission factors:

$$\text{VOC Emissions}\left(\frac{\text{ton}}{\text{mo}}\right) = \left[\text{EF}_A * \text{Feed}_A * \frac{1\text{ ton}}{2{,}000\text{ lb}}\right] - \left[\text{EF}_B * \text{Feed}_B * \frac{1\text{ ton}}{2{,}000\text{ lb}}\right]$$

Where for FCU 500 and FCU 600:
EF_A = 3.3 lb VOC/1000 barrels of feed
$Feed_A$ = Actual Feed (1000 barrels feed/month)
EF_B = 3.3 lb VOC/1000 barrels of feed
$Feed_B$ = Baseline Feed (1000 barrels feed/month)

$$\text{PM/PM10/PM2.5 Emissions}\left(\frac{\text{ton}}{\text{mo}}\right) = \left[\text{EF}_A * \text{coke}_A * \frac{1\text{ ton}}{2{,}000\text{ lb}}\right] - \left[\text{EF}_B * \text{coke}_B * \frac{1\text{ ton}}{2{,}000\text{ lb}}\right]$$

Where for FCU 500:
EF_A = 0.465 lb PM/PM_{10}/$PM_{2.5}$ per 1000 lb coke burned
$Coke_A$ = Actual coke burn rate (1000 lb/month)
EF_B = 0.465 lb PM/PM_{10}/$PM_{2.5}$ per 1000 lb coke burned
$Coke_B$ = Baseline coke burn rate (1000 lb/month)

Where for FCU 600:
EF_A = 0.35 lb PM/PM_{10}/$PM_{2.5}$ per 1000 lb coke burned
$Coke_A$ = Actual coke burn rate (1000 lb/month)
EF_B = 0.35 lb PM/PM_{10}/$PM_{2.5}$ per 1000 lb coke burned
$Coke_B$ = Baseline coke burn rate (1000 lb/month)

(d) The Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM, OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

Fugitive VOC emissions from valves, pumps, and flanges shall be determined as follows:

VOC Emissions (tpy) =

$N * (CE_{comp}) * [(EF_{leak} * Leak) + EF_{no\text{-}leak} * (1- Leak)] * VOC_{comp}$

Where:

N = No. of components added or removed (valve/pump/flange/drain/relief device)
VOC_{comp} = Percent VOC service for component
Leak = Fraction of components experiencing leaks

CE_{comp}= LDAR Control efficiency for the type of component (valve/pump/flange/drain/relief device)
EF_{leak} = EPA's refinery screening emission factor (leak) for type of component
$EF_{no\text{-}leak}$ = EPA's refinery screening emission factor (no leak) for type of component

For purposes of this calculation, new components are considered " added" on the date that a new or modified process unit starts up,

The decreases in fugitive VOC emissions from valves, pumps, flanges, drains and pressure relief devices, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for VOC for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

(e) For all emissions units involved in heavy liquid service, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service. The Permittee shall update the LDAR Plan to indicate that the methodologies in 40 CFR 60.482 shall apply to all pumps in heavy liquid service and shall submit a copy of the revised LDAR Plan to IDEM, OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

VOC emissions decreases from existing pumps in heavy liquid service shall be determined as follows:

Emissions decrease (tpy) = $N * (CE_{project} - CE_{current}) * [(EF_{leak} * Leak) + EF_{no\text{-}leak} * (1\text{-}Leak)] * VOC_{comp}$

Where:

N = No. of existing heavy liquid pumps
VOC_{comp} = Fraction of heavy liquid components in VOC service
$CE_{project}$ = Proposed control efficiency due to enhanced LDAR monitoring
$CE_{current}$ = Current control efficiency
EF_{leak} = EPA's refinery screening emission factor (leak)
$EF_{no\text{-}leak}$ = EPA's refinery screening emission factor (no leak)
Leak = Fraction of components experiencing leaks

(f) PM and PM-10 Emissions decreases from existing cooling towers (due to installation of any liquid drift eliminator) shall be calculated based on the following:

Emissions decrease = Baseline Emissions - Actual Emissions

Actual PM/PM-10 emissions =
(Recirculation Rate + Make-up Rate) (gal/min) x AP42 Ef (0.019 lb/1,000 gal) $(TLD_{design}/TLD_{AP\text{-}42}) \times (TDS_{allowable}/TDS_{AP\text{-}42})$

Where:

TLD = Total liquid drift, percentage
TDS = Total dissolved solids, mg/L

(g) Emissions from the GOHT, South, and HU flares shall be calculated as follows:

Emissions (ton/month) = EF_p x HI_i x 1 ton/2000 lbs

Where:

HI = Total actual heat input for the month, in mmBtu, of all gases burned in Flare i as a result of routine, or planned non-routine activities (e.g. planned startups and shutdowns of upstream units).

EF_p = The pollutants-specific emission factor (lb/mmBTU) set out below:

For SO2:

$$EF_p = \frac{C \times MW \times P \times (1/HHV_A)}{R \times T}$$

Where,

C = Flared gas total sulfur concentration (ppm)
MW = Molecular Weight (lb/lbmol)
P = Pressure (psia)
R = Ideal Gas Constant (psia*ft3/(lbmol*R))
T = Temperature (R)

HHV_A = Actual flare gas higher heating value (mmBtu/mmscf)

For NOx:

EF_p = 0.068 lb/mmBtu (+ fuel nitrogen component)

For VOC:

EF_p = 0.14 lb/mmBtu

For CO:

EF_p = 0.37 lb/mmBtu

For PM10/2.5:

EF_p = 0.0075 lb/mmBtu

For Pb:

EF_p = 4.9E-7 lb/mmBtu

For Hg:

EF_p = 1.8E-7 lb/mmBtu

For Be:

EF_p = 1.18E-8 lb/mmBtu

For H2SO4:

EF_p = 3% x (SO2 EF_p) x 98/64.06

(h) The installation and modification of all emission units designated as part of the CXHO project, and all projects resulting in emissions decreases necessary to ensure that this project is minor under 326 IAC 2-2 (PSD), 326 IAC 2-3 (Emission Offset), and 326 IAC 2-1.1-5 (nonattainment NSR), shall be completed no later than 180 days from the start-up of the New Coker and the re-start of the No. 12 Pipestill (after the completion of the permitted modifications), whichever occurs later. This shall be considered the completion of the CXHO project, and the end of the contemporaneous period for this project.

Compliance Determination Requirements

D.0.2 Operating Requirements

(a) After the installation of the continuous BTU analyzers at fuel mixing drums, in order to demonstrate compliance with emissions limitations, the continuous BTU analyzer shall be calibrated, maintained, and operated for determining compliance with the firing rate limits for heaters and boilers that are new, modified or affected units related to the CXHO project.

(b) Prior to the installation of the continuous BTU analyzers and during periods of time when the BTU analyzers are down, in order to demonstrate compliance with the firing rate limits on heaters and boilers involved in the CXHO project, the Permittee shall:

(1) Continuously monitor the fuel flow rates at the heaters and boilers;

(2) Conduct a monthly analysis of fuel gas samples taken once per week in order to determine monthly averaged BTU content of the fuel gas in each mixing drum; and

(3) Determine the monthly firing rates for heaters and boilers based on the fuel flow rates at each heater and boiler and the monthly averaged BTU content of the fuel gas in the mixing drums.

D.0.3 Testing Requirements

(a) Tests shall be conducted on new, modified and affected emission units that are included in the CXHO project, utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C - Performance Testing. PM-10 includes both filterable and condensible PM-10. For heaters with a maximum heat input greater than or equal to 100 MMBTU/hr and FCU 500 and FCU 600, these tests shall be repeated at least once every three years from the date of the previous valid compliance demonstration. For heaters with a maximum heat input greater than or equal to 50 MMBTU/hr but less than 100 MMBTU/hr and the SRU COT 1 and COT2, these tests shall be repeated at least once every four years from the date of the previous valid compliance demonstration. For heaters with a maximum heat input less than 50 MMBTU/hr, ~~T~~these tests shall be repeated at least once every five years from the date of the previous valid compliance demonstration. Subsequent compliance demonstrations shall include testing of a different emission unit than the emission unit tested for the previous compliance demonstration until all units within a group have been tested.

(b) Tests shall be conducted in accordance with the following deadlines:

(1) For a group that includes new or modified emission units (CO-1a, CO-1d, CO-3b, PM/VOC-1, PM/VOC-2, PM/VOC-3, PM/VOC-4a, PM/VOC-4b, VOC-6, PM/VOC-7, NOx-1, NOx-2, NOx-4, NOx-8, NOx-12), tests shall be conducted on one of the representative heaters in that group: within 180 days of startup of a new emission unit, or modification of an existing emission unit within that group.

(2) For a group that includes only existing affected units (CO-1b, CO-1c, CO-2, CO-3a, CO-4, PM/VOC-5a, PM/VOC-5b, PM/VOC-5c, PM/VOC-5d, PM/VOC-8, PM/VOC-9, NOx-3, NOx-5, NOx-6, NOx-7, NOx-9, NOx-10, NOx-11), tests shall be conducted on one of the representative heaters in that group within 180 days of the start-up of the New Coker (#2 Coker) and the re-start of the No. 12 Pipestill (after the completion of the permitted modifications), whichever occurs later.

(c) The emissions units to be tested in order to demonstrate compliance with Prevention of Significant Deterioration (326 IAC 2-2), Emission Offset (326 IAC 2-3) and Nonattainment NSR (326 IAC 2-1.1-5) minor limits shall be grouped as follows:

Table D.0.2 Test Groups			
Pollutant	Test Group ID	Emission Units in Group	Testing Frequency
	CO-1a	11A PS heater H-1X, 11C PS heater H-200 4 UF heaters F-2, F-3, F-8A, F-8B ARU heaters F-200A, F-200B ISOM heater H-1	Every 3 years
	CO-1b	11C PS heater H-300 4 UF heater F-4	Every 4 years
	CO-1c	11A PS heaters H-2, H-3 4 UF heaters F-1, F-5, F-7	Every 5 years
	CO-1d	4 UF heater F-6 BOU heater F-401 CFHU heaters F-801A, F-801B CRU heaters F-101, F-102	Every 5 years
	CO-2	DDU heaters WB-301, WB-302	Every 4 years
	CO-3a	HU heater B-501	Every 3 years
	CO-3b	GOHT heaters F-901A, F-901B	Every 5 years
	CO-4	CFHU heater F-801C	Every 5 years
	No stack test required (equipped with CO CEMS)	New Coker (#2 Coker) heaters H-201, H-202, H-203 12 PS heaters H-101A, H-101B, H-102 DHT heater B-601A New HU heaters HU-1, HU-2 SRU COT1, COT2 FCU 500, FCU 600 3 SPS boilers/duct burners 1, 2, 3, 4, 6 New Boiler 1, New Boiler 2	Not applicable

Table D.0.2 Test Groups			
VOC and PM/PM-10 * VOC test group only	PM/VOC-1	New Coker (#2 Coker) heaters H-201, H-202, H-203	Every 3 years
	PM/VOC-2	New HU heaters HU-1, HU-2	Every 3 years
	PM/VOC-3	SRU COT1, COT2	Every 4 years
	PM/VOC-4a	11C PS heater H-200 12 PS heaters H-101A, H-101B, H-102 ISOM heater H-1 HU heater B-501	Every 3 years
	PM/VOC-4b	BOU heater F-401 GOHT heaters F-901A, F-901B DHT heater B-601A	Every 5 years
	PM/VOC-5a	11A PS heater H-1X 4UF heaters F-2, F-3, F-8A,F-8B ARU heaters F-200A, F-200B	Every 3 years
	PM/VOC-5b	11C PS heater H-300 4UF heater F-4 DDU heaters WB-301, WB-302	Every 4 years
	PM/VOC-5c	11A PS heaters H-2, H-3 4UF heaters F-1F-5, F-7	Every 5 years
	PM/VOC-5d	4UF heater F-6 CFHU heaters F-801A, F-801B, F-801C CRU heaters F-101, F-102	Every 5 years
	VOC-6*	3 SPS boilers 1, 2, 3, 4, 6	Every 3 years
	PM/VOC-7	New Boiler 1, New Boiler 2	Every 3 years
	PM/VOC-8	FCU 500	Every 3 years
	PM/VOC-9	FCU 600	Every 3 years
NOx	NOx-1	CFHU heater F-801C GOHT heaters F-901A, F-901B DDU heater WB-301	Every 4 years
	NOx-2	11C PS heater H-200	Every 3 years
	NOx-3	CRU heaters F-101, F-102	Every 5 years

Table D.0.2 Test Groups			
	NOx-4	4UF heaters F-3, F-4, F-8A, F-8B ARU heaters F-200A, F-200B ISOM H-1	Every 3 years
11C PS heater H-300	NOx-5	4UF heater F-2	Every 3 years
	NOx-6	11A PS heater H-1X	Every 3 years
	NOx-7	11C PS Heater H-300	Every 4 years
	NOx-8	11A PS heater H-2, H-3 4UF heaters F-1, F-5, F-6, F-7 BOU heater F-401	Every 5 years
	NOx-9	CFHU heaters F-801A, F-801B	Every 5 years
	NOx-10	HU heater B-501	Every 3 years
	NOx-11	DDU heater WB-302	Every 4 years
	NOx-12	SRU COT1, COT2	Every 4 years
	No stack test needed (NOx CEMS)	3 SPS boilers 1, 2, 3, 4, 6, New Boiler 1, New Boiler 2 New Coker (#2 Coker) heaters H-201, H-202, H-203 12 PS heaters H-101A, H-101B, H-102 New HU heaters HU-1, HU-2, FCU 500, FCU 600 DHT heater B-601A	Not applicable

(d) Within 180 days of the startup of New Coker (#2 Coker) and the re-start of the No. 12 Pipestill (after the completion of the permitted modifications), whichever occurs later, in order to demonstrate compliance with the PM-10 emission factor limit from the SCR stacks at No. 3 Stanolind Power Station (3 SPS), testing shall be conducted on one (1) of the five (5) stacks for 3 SPS boiler/SCR stacks, utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C - Performance Testing. PM-10 includes filterable and condensible PM-10. This test shall be repeated at least once every three years from the date of the previous valid compliance demonstration.

(e) Compliance with the emissions limits for each emission unit or test group shall be determined as follows:

$$T = \left(\sum_{i=1}^{n} T_i\right) / n$$

Where:
T = average of IDEM approved stack test results for emission unit or all units within that same group over a 12 month period
Ti = average of multiple runs during Test #i
n = number of IDEM approved stack tests during 12 month period

Recordkeeping and Reporting Requirements

D.0.4 Recordkeeping Requirements

In order to demonstrate compliance with Condition D.0.1, the Permittee shall maintain the following records each month, upon issuance of the SPM 089-25488-00453:

(a) The emissions in tons, calculated in accordance with D.0.1, including fugitive emissions, of PM, PM-10, VOC, NOx, CO, Pb, Be, Hg, H2SO4, and SO2, from new emission units installed as part of the CXHO project during that month.

(b) The emissions increases and decreases from CXHO related projects, including modifications, shutdowns, and installation of controls, and emissions increases from existing affected units during the past 12 months.

(c) Emissions increases and decreases from non-CXHO related projects during the past 12 months.

(d) The net emissions increases or decreases as calculated each month in Condition D.0.1(a).

D.0.5 Reporting Requirements

(a) In order to demonstrate compliance with Condition D.0.1, no later than 45 days after the end of the first 12- calendar month period following the effective date of SPM 089-25488-00453, and every 6 months thereafter, the Permittee shall submit a report to IDEM documenting the net emissions increases or decreases for the CXHO project as calculated each month, as required in Condition D.0.1.

SECTION D.1 FACILITY OPERATION CONDITIONS - No. 11 Pipe Still

Facility Description [326 IAC 2-7-5(15)]:

(a) Nos. 11A and 11C Pipe Stills built in 1956, with a rated capacity of 220,800 barrels per day, and identified as Unit ID 120 process crude into various hydrocarbon fractions based on boiling points. This facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) The following process heaters, all of which are fired by natural gas, refinery gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-1X	250	120-01	None
H-2	45	120-02	None
H-3	55	120-03	None
H-200	249.5	120-05	Current (None) After CXHO (Low-Nox burners)
H-300	180	120-06	None

(2) Two (2) vacuum hot wells (D-21, constructed in 1990 and D-26, constructed in 1997) and one (1) sump (D-20, constructed in 1990), with D-20, D-21, and D-26 each venting to S/V 120-07, at No. 11 A Pipe Still.

(3) One (1) vacuum hot well (D-300), constructed in 1995 venting to S/V 120-08 at No. 11C Pipe Still.

The vacuum tower overhead system consists of a series of condensers, steam ejectors, and vacuum pumps. The majority of the overhead vapors are condensed and drained to the hotwell, which is pumped back to the front end of the unit for reprocessing. The gas compressors pull the remaining vapor that is not condensed in the overhead system into the wet gas system, where the hydrocarbon is reprocessed by down steam units. A thermocouple system (with temperature alarm) is used to monitor the vacuum on the system.

(4) Leaks from process equipment, including pumps; compressors (K4 and K4A at No. 11A Pipe Still and K300A and K300-B at the No. 11C Pipe Still); pressure relief devices; sampling connection systems; open-ended lines or valves; and instrumentation systems.

(5) One (1) storage tank (identified as Tank 3030) with a maximum storage capacity of 847,000 gallons. This tank was installed in 1957 and is equipped with an external floating roof.

(6) One (1) oil water separation system (identified as Tank 8), with a maximum storage capacity of 124,800 gallons.

(7) One (1) redundant oil water separation system (identified as Tank 8a), permitted in 2008, with a maximum storage capacity of 124,800 gallons, equipped with a carbon canister for VOC control.

(8) As part of the No. 11A PS and No. 11C PS WARP, permitted in 2008, the two existing blowdown stacks identified as stacks 11PS A and 11PS C will be shutdown, with the emergency pressure relief discharge that was previously routed to the blowdown stacks being re routed to the DDU flare, except for T 300 vacuum tower relief discharge and the COV's.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.1.1.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008) the Permittee shall comply with the following PM10 emission limitations for No. 11 pipe still (including nos. 11A and 11C pipe still) process heaters:

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
H-1X Heater	0.0075	1.863
H2 Vacuum Heater	0.0075	0.335
H3 Vacuum Heater	0.0075	0.41
H-200 Crude Charge	0.0075	1.859
H-300 Furnace	0.0075	1.341

D.1.1.2 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), the Permittee shall comply with the following filterable PM10 emission limitations for Nos. 11A and 11C Pipe Still process heaters:

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
H-1X Heater	0.031	6.867
H2 Vacuum Heater	0.032	1.440
H3 Vacuum Heater	0.031	1.704
H-200 Crude Charge	0.032	7.866
H-300 Furnace	0.031	4.931

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.1.1.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for

inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.1.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) After the startup of the low-NOx burners on heater H-200, the emissions of NOx shall not exceed 0.05 pounds per million BTU of fuel gas fired.

(b) The Permittee shall comply with the following limits following the startup of the new Coker (#2 Coker):

(1) Annual firing rate and SO2 emissions limits:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO2 emissions (tons per 12 consecutive month period)
H-200	1601.33	8.9
H-300	630.72	3.5
H-1X	1523.36	8.4
H-2	282.95	1.6
H-3	430.99	2.4

(2) CO, VOC, NOx, PM and PM-10 emissions limits:

Heater ID	CO (lb/mmBTU)	VOC (lb/mmBTU)	NOx (lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
H-1X	0.082	0.0054	0.166	0.0019	0.0075
H-2	0.082	0.0054	0.098	0.0019	0.0075
H-3	0.082	0.0054	0.098	0.0019	0.0075
H-200	0.082	0.0054	0.2745*	0.0019	0.0075
H-300	0.082	0.0054	0.137	0.0019	0.0075

* 0.05 lb/mmBTU after startup of low-NOx burners

(c) After the startup of the New Coker (#2 Coker), the two existing blowdown stacks identified as stacks 11PS-A and 11PS-C will be shutdown, with the emergency pressure relief discharge that was previously routed to the blowdown stacks being re-routed to the DDU flare, except for T-300 vacuum tower relief discharge and the COV's.

(d) The following heaters shall not combust any fuel oil: H-1X, H-2, H-3, H-200, H-300.

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.1.3 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, the Permittee shall comply with the following sulfur dioxide emission limitations for the No. 11 (including Nos. 11A and 11C) Pipe Still process heaters:

Process Heater	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)
H-1X Heater	0.033	8.25
H-2 Vacuum Heater	0.033	1.49
H-3 Vacuum Heater	0.033	1.82
H-200 Crude Charge	0.033	8.23
H-300 Furnace	0.033	5.94

D.1.4 SO_2 Emission Limitations

Pursuant to Permit CP 089-3053-00003, issued on March 31, 1994, the Permittee shall comply with the following SO_2 emission limitations for No. 11 (including Nos. 11A and 11C) Pipe Still process heaters:

Process Heater	SO_2 Limit (lbs/MMBtu)
H-1X Heater	0.358
H-300 Furnace	0.357

D.1.5 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for process heaters: H-1X Heater, H-2 Vacuum Heater, H-3 Vacuum Heater, H-200 Crude Charge, and H-300 Furnace.

D.1.6 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems located at No. 11A Pipe Still.

(c) Prior to startup of Tank 8a, BP shall make a determination as to whether 40 CFR 60 Subpart GGGa has been triggered by the changes made as a part of the projects authorized by SSM 089-25484-00453. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.1.7 Volatile Organic Compounds (VOC) [326 IAC 8-4-2]

(a) Pursuant to 326 IAC 8-4-2(1), the Permittee shall control VOC emissions from the vacuum producing systems at the No. 11A Pipe Still vacuum hot wells (D-20, D-21, and D-26) and No. 11C Pipe Still vacuum hot well (D-300) according to the following:

The Permittee shall not emit any noncondensable volatile organic compounds from the condensers, hot wells or accumulators of any vacuum producing systems at a petroleum refinery.

(b) Pursuant to 326 IAC 8-4-2(2), the Permittee shall equip the wastewater (oil/water) separators Tank 8 and Tank 8a, any forebay, and openings in covers with lids or seals such that the lids or seals are in the closed position at all times except when performing maintenance.

D.1.8 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14][40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ] [326 IAC 12]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF:

(1) The Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(2) The Permittee shall operate tank 3030 in accordance with the requirements in Sections E.1 and E.3 by complying with the requirements in Section E.9, except as provided for in 40 CFR 63.640(n)(8) and listed in Section E.1.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

Compliance Determination Requirements

D.1.9 Operating Requirement

(a) Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002, effective June 1, 2003, fuel oil shall not be used as a fuel for the Nos. 11A and 11C Pipe Stills.

(b) In order to demonstrate compliance with Condition D.1.2, following the installation of the low-NOx burners the heater H-200 shall operate using only low-NOx burners.

(c) Compliance with the limits in Condition D.1.2(b)(2) shall be demonstrated as specified in Condition D.0.3.

(d) In order to demonstrate compliance with Condition D.1.2, following the startup of New Coker (#2 Coker), the pressure relief discharge that was previously routed to the blowdown stacks will be routed to the DDU flare, except for T-300 vacuum tower relief discharge and the COV's. The flare must be operated with a flame present at all times that 11A PS or 11C PS is in operation.

D.1.10 Operating Requirement

Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.1.3 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

D.1.11 Continuous Emissions Monitoring

In order to demonstrate compliance with Condition D.1.2, the Total Reduced Sulfur continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for H-1X, H-2, H-3, H-200 and H-300 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.1.12 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.1.13 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.1.3 and D.1.9, the Permittee shall maintain a daily record of the following for Nos. 11A and 11C Pipe Stills:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.1.1, Permittee shall maintain records for the Nos. 11A and 11C Pipe Still process heaters as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.1.5, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.1.6(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR Plan.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.1.6(b), the Permittee shall keep records as specified in Section E.1 and E.4.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.1.8(a)(1), the Permittee shall keep records as specified in Sections E.1 and E.3.

(g) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.1.8(a)(2), the Permittee shall keep records as specified in Sections E.1, E.3, and E.9.

(h) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.1.8(b), the Permittee shall keep records as specified in Section E.6.

(i) In order to demonstrate compliance with Condition D.1.2, the Permittee shall maintain records of monthly firing rates and SO2 emissions for H-1X, H-2, H-3, H-200, and H-300.

(j) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.1.2, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.1.14 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.1.3, D.1.4 and D.1.9, the Permittee shall submit a report to the IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour for Nos. 11A and 11C Pipe Still process heaters.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.1.5, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.1.6(a), the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.1.6(b), the Permittee shall submit records as specified in Section E.1 and E.4.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.1.8(a)(1), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.1.8(a)(2), the Permittee shall submit reports as specified in Sections E.1, E.3, and E.9.

(g) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.1.8(b), the Permittee shall submit reports as specified in Section E.6.

(h) In order to demonstrate compliance with Condition D.1.2, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions for heaters H-200, H-300, H-1X, H-2, and H-3 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(i) Pursuant to 326 IAC 3-5-7 and to document compliance with Condition D.1.2 and D.1.11, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.2 FACILITY OPERATION CONDITIONS - No. 11B Coker and Coke Pile

Facility Description [326 IAC 2-7-5(15)]:

(b) No. 11B Coker, which processes heavy crude fractions into coke, and Coke Pile. These facilities are identified as Unit 120 and are rated at 2,000 tons of coke per day. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) Process heaters comprising:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-101 H-102 H-103 H-104	200 (total)	120-04	None

(2) Storage and handling of the bulk material. Fugitive emissions are controlled by keeping the coke wetted and having a 15' sheet piling wall surrounding the coke pile. The coke pile height will not exceed 15'.

(3) The No. 11B Coker is connected to the DDU flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves, flanges and other connectors.

New Coker (#2 Coker), which processes heavy crude fractions into coke, and new Coke Handling System. These facilities are identified as Unit 800 and are rated at 6,000 tons of coke per day. The New Coker (#2 Coker) heaters H-201, H-202, and H-203 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New Coker (#2 Coker) heater stacks have continuous emissions monitors (CEMS) for NOx and CO. The existing Coker and Coke Pile will be replaced as part of the CXHO Project. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) Process heaters comprising:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-201	208	800-01	Low NOX burners and selective catalytic reduction
H-202	208	800-02	Low NOX burners and selective catalytic reduction
H-203	208	800-03	Low NOX burners and selective catalytic reduction

(2) Storage and handling (including up to 10 transfer points) of the bulk material comprised of a partially enclosed crusher, enclosed conveyors, enclosed storage, day bins, and rail car load out under the main operating scenario. In order to minimize fugitive emissions from the coke handling process, transfer points 1 and 10 will include enclosed conveyors and transfer points 2 through 9 will use enclosed buildings, and water sprays. Coke handling operations will be expected to operate under this main operating scenario for at least 95% of operating hours annually. There will also be an alternative operating scenario which will consist of three enclosed conveyors with unenclosed transfer points. Coke handling operations are expected to operate under this alternate operating scenario for no more than 5% of operating hours annually.

(3) The Coker is connected to the South flare system (included in Section D.35). The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) One (1) storage tank, identified as TK-6255, with a maximum storage capacity of 14,028,000 gallons storing coker resid at a vapor pressure less than 0.5 psia. Tank TK-6255 is equipped with a fixed roof.

(5) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves, flanges or other connectors, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.2.1.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Until the shutdown of the No. 11B Coker and Coke Pile and the heaters identified as H-101, H-102, H-103, H-104, pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008) PM10 emissions from the stack serving No. 11 pipe still furnaces H-101, H-102, H-103, and H-104 coke preheaters shall not exceed 0.0075 lb/MMBTU and 1.49 lb/hr (total).

(b) Until the shutdown of the No. 11B Coker and Coke Pile and the heaters identified as H-101, H-102, H-103, H-104, pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

(c) Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from each of the New Coker (#2 Coker) stacks 800-01, 800-02, and 800-03 shall not exceed 0.03 grains per dry standard cubic foot.

D.2.1.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8]

Until the shutdown of the No. 11B Coker and Coke Pile and the heaters identified as H-101, H-102, H-103, H-104, pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005) filterable PM10 emissions from the stack serving No. 11 pipe still furnaces H-101, H-102, H-103, and H-104 coke preheaters shall not exceed 0.004 lb/MMBTU and 0.741 lb/hr (total).

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.2.1.1 as part of the Indiana State Implementation Plan.

D.2.2 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

(a) After the permanent shutdown of No. 11 B Coker and Coke Pile, the throughput of coke processed at the New Coker (#2 Coker) shall not exceed 2,190,000 tons per twelve (12) consecutive month period, with compliance determined at the end of each month, and the coke handling operations shall not operate under the alternative operating scenario for more than 438 hours per twelve (12) consecutive month period.

(b) The No. 11B Coker, Coke Pile, and heaters H-101, H-102, H-103, and H-104 shall be permanently shutdown as part of the CXHO project.

For each of the heaters H-201, H-202, and H-203:

(c) The emissions of NOx from each shall not exceed 18.2 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(e) The emissions of SO2 from each shall not exceed 10.1 tons per 12 consecutive month period, with compliance determined at the end of each month.

(f) The emissions of PM and PM-10 each shall not exceed 0.0019 and 0.0081 pounds per million BTU.

(g) The emissions of CO from each shall not exceed 17.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(h) The Permittee shall comply with the following fuel usage limits per twelve (12) consecutive month period, with compliance determined at the end of each month:

Unit ID	Firing rate limit (10^3 mmBTU) per 12 consecutive month period
H-201	1822.1
H-202	1822.1
H-203	1822.1

Compliance with the coker throughput limits and limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.2.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Until the shutdown of the heaters identified as H-101, H-102, H-103, H-104:

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from the H-101, H-102, H-103, and H-104 No. 11B Coker process heaters shall each not exceed 0.033 lbs/MMBtu and the total sulfur dioxide emissions from all four process heaters shall not exceed 6.60 lbs per hour.

D.2.4 Volatile Organic Liquid Storage Vessels [326 IAC 8-9-6]

Pursuant to 326 IAC 8-9-6(b), for storage tank TK-6255, which is used to store liquids with vapor pressures less than 0.5 psia, the Permittee shall comply only with the recordkeeping requirements specified in Condition D.2.16(h).

D.2.5 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

(a) Until the shutdown of the heaters identified as H-101, H-102, H-103, H-104, pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the process heaters H-101, H-102, H-103, and H-104 No. 11B.

(b) Upon startup of New Coker (#2 Coker) heaters H-201, H-202, H-203, Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for process heaters H-201, H-202 and H-203.

D.2.6 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.2.7 Hazardous Air Pollutants (HAP)[326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the storage tank TK-6255 shall comply with the requirements under 40 CFR 63.640(l)(3) through l(3), as specified in Section E.1.

D.2.8 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]] [40 CFR 60, Subpart QQQ] [326 IAC 12]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.2.9 Lake County Fugitive Particulate Matter Control Requirements [326 IAC 6.8-10]

The Permittee shall comply with the following for the No. 11B Coker and Coke Pile until it is permanently shutdown, and for the New Coker (#2 Coker) and Coke Handling System upon startup:

Pursuant to 326 IAC 6.8-10-3(3)(A), (3)(B), (5), and (6) (formerly 326 IAC 6-1-11.1(d)(3)(A), (3)(B), (5), (6)(A) and (d)(6)(B)), the Permittee shall comply with the opacity limitations in Condition C.6 (Fugitive Dust Emissions) for batch material transfer, wind erosion from storage piles, and material transfer by front end loader and truck. Opacity from the activities shall be determined as follows:

(a) Batch Transfer - The average instantaneous opacity shall consist of the average of three (3) opacity readings taken five (5) seconds, ten (10) seconds, and fifteen (15) seconds after the end of one (1) batch loading or unloading operation. The three (3) readings shall be taken at the point of maximum opacity. The observer shall stand approximately fifteen (15) feet from the plume and at approximately right angles to the plume.

(b) Wind Erosion from Storage Piles - The opacity shall be determined using 40 CFR 60, Appendix A, Method 9, except that the opacity shall be observed at approximately four (4) feet from the surface at the point of maximum opacity. The observer shall stand approximately fifteen (15) feet from the plume and at approximately right angles to the plume. The limitations may not apply during periods when application of fugitive particulate control measures are either ineffective or unreasonable due to sustained very high wind speeds. During such periods, the company shall continue to implement all reasonable fugitive particulate control measures and maintain records documenting the application of measures and the basis for a claim that meeting the opacity limitation was not reasonable given prevailing wind conditions.

(c) Material Transported by Truck or Rail - Compliance with this limitation shall be determined by 40 CFR 60, Appendix A, Method 22, except that the observation shall be taken at approximately right angles to the prevailing wind from the leeward side of the truck or railroad car. Material transported by truck or rail that is enclosed and covered shall be considered in compliance with the inplant transportation requirement.

(d) Material Transported by Front End Loader or Skip Hoist - Compliance with this limitation shall be determined by the average of three (3) opacity readings taken at five (5) second intervals. The three (3) opacity readings shall be taken as follows:

(1) The first will be taken at the time of emission generation.

(2) The second will be taken five (5) seconds later.

(3) The third will be taken five (5) seconds later or ten (10) seconds after the first.

Compliance Determination Requirements

D.2.10 Operating Requirement

(a) Until the shutdown of the No. 11B Coker and the associated emissions units:

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the No. 11B Coker furnaces.

(b) Compliance with the limits in Condition D.2.2(d) and (f) shall be demonstrated as specified in Condition D.0.3.

D.2.11 Fugitive Dust Control Plan [326 IAC 6.8-10]

(a) Until the shutdown of the No. 11B Coker and the associated emissions units:

Pursuant to 326 IAC 6.8-10-4 (formerly 326 IAC 6-1-11.1) the Permittee shall control fugitive particulate matter emissions from No. 11B Coker and Coke Handling System according to the Fugitive Dust Control Plan (FDCP), included as Appendix C. If it is determined that the control procedures specified in the FDCP do not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require that the FDCP be revised and submitted for approval.

(b) Pursuant to 326 IAC 6.8-10-4 (formerly 326 IAC 6-1-11.1), the Permittee shall control fugitive particulate matter emissions from the New Coker (#2 Coker) and Coke Handling System according to the updated Fugitive Dust Control Plan (FDCP) submitted on January 30, 2008, included as Appendix C. If it is determined that the control procedures specified in the FDCP do not demonstrate compliance with the fugitive emissions limitations, IDEM, OAQ may require that the FDCP be revised and submitted for approval.

D.2.12 Operating Requirement

(a) Until the shutdown of the No. 11B Coker and heaters, pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.2.4 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) In order to demonstrate compliance with Condition D.2.2, the Permittee shall operate the heaters H-201, H-202, and H-203 using only low-NOx burners.

(c) In order to comply with Condition D.2.2, the SCRs shall be operated as necessary to meet the NOx emissions limits for heaters H-201, H-202 and H-203**.**

D.2.13 Continuous Emissions Monitoring

The Total Reduced Sulfur, CO, and NOx continuous emission monitoring systems (CEMS) for H-201, H-202, and H-203 shall be calibrated, maintained, and operated for determining compliance with the SO2, CO and NOx emissions limits in Condition D.2.2 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

D.2.14 PM and PM-10

In order to comply with Condition D.2.2, the Permittee shall use wet suppression to control emissions of PM and PM10 from transfer points 1 through 10 at New Coker (#2 Coker) as necessary to ensure that the coke processed has a moisture content greater than eight percent. The suppressant shall be applied in a manner and at a frequency sufficient to ensure compliance with Condition D.2.2.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.2.15 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.2.16 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.2.3 and D.2.11, the Permittee shall maintain a daily record of the following for the No. 11B Coker process heaters:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

The Permittee shall comply with this requirement until the shutdown of the No. 11B Coker and the associated emissions units.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.2.1, Permittee shall maintain records for the No. 11B Coker process heaters as specified in the Continuous Compliance Plan. The Permittee shall comply with this requirement until the shutdown of the No. 11B Coker and the associated emissions units.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.2.5, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.2.6(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC and to document compliance with Condition D.2.6(b), the Permittee shall keep records as specified in Sections E.1, E.25 and E.26.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.2.8, the Permittee shall keep records as specified in Sections E.1 and E.3.

(g) Pursuant to 326 IAC 6.8-10-4(4) (formerly 326 IAC 6-1-11.1(e)(4)) and to document compliance with Condition D.2.9, for the Coke Pile, the Permittee shall keep the following documentation:

(1) A map or diagram showing the location of all fugitive PM emission sources controlled,

(2) For application of physical or chemical control agents, the following:

(A) The name of the agent

(B) Location of application

(C) Application rate

(D) Total quantity of agent used

(E) If diluted, percent of concentration

(F) The material data safety sheets for each chemical

(3) A log recording incidents when control measures were not used and a statement of explanation.

(4) Copies of all records required by this section shall be submitted to IDEM, OAQ within twenty (20) working days of a written request by IDEM, OAQ.

(h) Pursuant to 326 IAC 8-9-6(b), the Permittee shall maintain, for the life of the vessel, a record of the following for tank TK-6255 to which 326 IAC 8-9 applies:

(1) The vessel identification number,

(2) The vessel dimensions,

(3) The vessel capacity, and

(4) A description of the emission control equipment for each vessel described in section 4(a) or 4(b) of 326 IAC 8-9, or a schedule for installation of emission control equipment on vessels described in section 4(a) or 4(b) of 326 IAC 8-9 with a certification that the emission control equipment meets the applicable standards.

(i) In order to demonstrate compliance with Condition D.2.2, the Permittee shall maintain records of monthly firing rates and CO, NOx, and SO2 emissions for heaters H-201, H-202, and H-203.

(j) In order to demonstrate compliance with Condition D.2.2, the Permittee shall maintain records of monthly coke throughput at the New Coker (#2 Coker).

(k) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.2.13 the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.2.17 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.2.3 and D.2.10, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the No. 11B Coker process heaters. The Permittee shall comply with this requirement until the shutdown of the No. 11B Coker and the associated emissions units.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.2.5, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.2.6(a), the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC and to document compliance with Condition D.2.6(a), the Permittee shall submit reports as specified in Sections E.1, E.25 and E.26.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.2.8, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(f) Pursuant to 326 IAC 6.8-10-4(4)(G) (formerly 326 IAC 6-1-11.1(e)(4)(G)) and to document compliance with Condition D.2.11, a quarterly report shall be submitted within thirty (30) days of the end of each quarter, stating the following:

(1) The dates any required control measures were not implemented

(2) A listing of those control measures

(3) The reasons that the control measures were not implemented

(4) Any corrective action taken

(g) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.2.2 and D.2.13, the Permittee shall submit reports of excess SO2, CO and NOx emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

(h) In order to demonstrate compliance with Condition D.2.2, the Permittee shall submit quarterly reports for the monthly firing rates, and CO, NOx, and SO2 emissions at heaters H-201, H-202, and H-203. The report submitted by the Permittee does require the certification by the “Responsible Official” as defined by 326 IAC 2-7-1(34).

(i) In order to demonstrate compliance with Condition D.2.2, the Permittee shall submit quarterly reports for the coke throughput at the New Coker (#2 Coker) and the number of hours the coke handling operated under alternative operating scenario. The report submitted by the Permittee does require the certification by the “Responsible Official” as defined by 326 IAC 2-7-1(34).

SECTION D.3 FACILITY OPERATION CONDITIONS – No. 12 Pipe Still

Facility Description [326 IAC 2-7-5(15)]:

(c) No. 12 Pipe Still, constructed in 1959, to be modified as part of the CXHO Project, which processes crude into various hydrocarbon fractions based on boiling points, identified as Unit ID 130, and is rated at 336,000 barrels per day. Heaters identified as H-1AN, H-1AS, H-1B, H-2, H-1CN and H-1CX will be shutdown and replaced by heaters H-101A, H-101B, and H-102 as part of the CXHO project. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) The following process heaters, all of which are fired by natural gas, refinery gas, or liquified petroleum gas:

Heater Identification	Construction Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-1AN	1959	121.5	130-01	None
H-1AS	1959	121.5	130-01	None
H-1B	1959	243	130-01	None
H-2	1959	174	130-01	Ultra low NO_x burners
H-1CN	1967/1995	120	130-02	Low NO_x burners
H-1CX	1977	410	130-04	Low NO_x burners
H-101A	Permitted in 2008	355	130-05	Ultra low-NO_X burners
H-101B	Permitted in 2008	355	130-07	Ultra low-NOx burners
H-102	Permitted in 2008	331	130-06	Ultra low-NO_X burners

a No longer in service -- was rated at 120 MMBtu/hour.
b No longer in service -- was exhausted to stack 130-03.

(2) One (1) vacuum hot well, identified as D-7, constructed in 1995, and venting to S/V 130-05. The vacuum tower overhead system consists of a series of condensers, steam ejectors, and vacuum pumps. The majority of the overhead vapors are condensed and drained to the hotwell, which is pumped back to the front end of the unit for reprocessing. The gas compressors pull the remaining vapor that is not condensed in the overhead system into the wet gas system, where the hydrocarbon is reprocessed by down stream units. A thermocouple system (with temperature alarm) is used to monitor the vacuum on the system.

(3) Leaks from process equipment, including compressors (K-1, K-1A, and K-1B), valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and flanges.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.3.1.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008) the

Permittee shall comply with the following PM10 emission limitations for the No. 12 Pipe Still process heaters until these heaters are shutdown as part of the CXHO project:

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
Stack serving H-1AN, H-1AS, H-1B Preheaters and H-2 Vacuum Heater	0.0075	4.918

(b) Until the shutdown of heaters H-1CN and H-1CX, pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the PM10 emissions from H-1CN and H-1CX shall not exceed 0.0075 lb/MMBTU for both heaters and 0.894 and 3.055 lb/hr for H-1CN and H-1CX, respectively.

D.3.1.2 Lake County PM10 (filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005) the Permittee shall comply with the following filterable PM10 emission limitations for the No. 12 Pipe Still process heaters until these heaters are shutdown as part of the CXHO project:

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
Stack serving H-1AN, H-1AS, H-1B Preheaters and H-2 Vacuum Heater	0.025	16.348

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.3.1.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition (until shutdown) in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.3.2 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from each of the three (3) heaters H-101A, H-101B and H-102 shall not exceed 0.03 grains per dry standard cubic foot.

D.3.3 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, the Permittee shall comply with the following sulfur dioxide emission limitations for the No. 12 Pipe Still process heaters (until these heaters are shutdown):

Process Heater	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)
H-1AS and H-1AN Preheaters	0.033	21.78
H-1B Preheater	0.033	

Process Heater	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)
H-2 Vacuum Heater	0.033	
H-1CN Crude Preheater	0.033	7.92
H-1CX Crude Preheater	0.033	13.53

D.3.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

(a) Pursuant to SPM 089-15202-00003, issued on April 24, 2002 and 40 CFR 60.104(a)(1), until these heaters are shutdown, the Permittee shall comply with the requirements specified in Section E.2 for the following process heaters: H-1AS and H-1AN Preheaters, H-1B Preheater, H-2 Vacuum Heater, H-1CN Crude Preheater, and H-1CX Crude Preheater.

(b) The Permittee shall comply with the requirements specified in Section E.2 for the following process heaters: H-101A, H-101B, and H-102.

D.3.5 Emission Offset [326 IAC 2-3], Prevention of Significant Deterioration [326 IAC 2-2] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

(a) Pursuant to CP 089-2055-00453 issued on March 12, 1992, until heater H-1CX is shutdown, nitrogen oxide emissions from the 12 Pipe Still H-1CX furnace shall not exceed 0.10 lb/MMBtu. Compliance with this limit renders 326 IAC 2-3 not applicable. The H-1CX furnace shall also be equipped with low NO_x burners.

In order to render 326 IAC 2-2-8, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable:

(b) The Permittee shall comply with the following limits for the heaters identified as H-101A, H-101B and H-102, with compliance with the annual NOx, CO, and SO2 limits determined at the end of each month):

Heater ID	NOx tons per 12 consecutive month period	SO2 tons per 12 consecutive month period	CO tons per 12 consecutive month period)	VOC (lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
H-101A	77.7	17.2	29.5	0.0054	0.0019	0.0075
H-101B	77.7	17.2	29.5	0.0054	0.0019	0.0075
H-102	72.5	16.0	27.5	0.0054	0.0019	0.0075

(c) The Permittee shall comply with the following limits on firing rates:

Unit ID	Firing rate limit (10^3 mmBTU) per 12 consecutive month period
H-101A	3109.8
H-101B	3109.8
H-102	2899.6

(d) The heaters H-1AN, H-1AS, H-1B, H-2, H-1CN, and H-1CX shall be permanently shutdown prior to the completion of the CXHO project.

(e) The following heaters and preheaters shall not combust any fuel oil: H-1AN, H-1AS, H-1B preheaters, H-2 vacuum heaters.

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.3.6 Equipment Leaks of VOC and Hazardous Air Pollutants (HAPs)[326 IAC 12] [326 IAC 8-4-8] [40 CFR 60, Subpart GGGa] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.25 and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.3.7 Volatile Organic Compounds (VOC) [326 IAC 8-4-2]

Pursuant to 326 IAC 8-4-2(1), the Permittee shall control VOC emissions from No. 12 Pipe Still vacuum hot well, D-7, according to the following:

No owner or operator of any vacuum producing systems at a petroleum refinery may cause, allow or permit the emission of any noncondensable volatile organic compounds from the condensers, hot wells or accumulators of the system.

D.3.8 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ] [326 IAC 12]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

D.3.9 Prevention of Significant Deterioration (PSD) Minor Limit [326 IAC 2-2]

Pursuant to SPM 089-15202-00003, issued April 24, 2002 and SPM 089-18588-00453, issued July 15, 2004, nitrogen oxide emissions from the Heater H-2 (until shutdown) shall be controlled by low-NO_x burners having an emission rate of 0.044 pounds per million Btu or less. This condition renders the requirements of 326 IAC 2-2 not applicable.

Compliance Determination Requirements

D.3.10 Operating Requirement

(a) Pursuant to SPM 089-15202-00003, issued April 24, 2002, fuel oil shall not be used as fuel for the No. 12 Pipe Still.

(b) In order to demonstrate compliance with Condition D.3.5(b), the heaters H-101A, H-101B, and H-102 shall operate using ultra-low NOx burners only.

(c) Compliance with the lb/mmBTU limits in Condition D.3.5(b) shall be demonstrated as specified in Condition D.0.3.

D.3.11 Continuous Emissions Monitoring

The Total Reduced Sulfur, NOx, and CO continuous emission monitoring systems (CEMS) for H-101A, H-101B, and H-102 shall be calibrated, maintained, and operated for determining compliance with the SO2, NOx, and CO emissions limits in Condition D.3.5 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

D.3.11 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

(a) Within 36 months after the effective date of this permit, in order to demonstrate compliance with Condition D.3.4, the Permittee shall perform NO_x testing of the H-1CX heater utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C-Performance Testing.

(b) Within 5 years of last compliant stack test, the Permittee shall perform NO_x testing of the H-2 heater utilizing methods approved by the Commissioner, in order to demonstrate compliance with Condition D.3.9. Testing shall be conducted in accordance with Section C – Performance Testing.

D.3.12 Operating Requirement

Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.3.3 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.3.13 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.3.14 Continuous Emissions Monitoring

In order to demonstrate compliance with Conditions D.3.5 and D.3.12, the Total Reduced Sulfur, NOx, and CO continuous emission monitoring systems (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2, NOx, and CO emissions limits for H-101A, H-101B, and H-102 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

D.3.15 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.3.3, and D.3.10, the Permittee shall maintain a daily record of the following for No. 12 Pipe Still:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each fuel type, and

(5) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.3.1, Permittee shall maintain records for the No. 12 Pipe Still process heaters H-1AS and H-1AN Preheaters, H-1B Preheater, H-2 Vacuum Heater, H-1CN Crude Preheater, and H-1CX Crude Preheater as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.3.4, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.3.6(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Condition D.3.6(b), the Permittee shall keep records as specified in Sections E.1, E.4 and E.13.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.3.8, the Permittee shall keep records as specified in Sections E.1 and E.3.

(g) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.3.8(b), the Permittee shall keep records as specified in Section E.6.

(h) In order to demonstrate compliance with Condition D.3.5, the Permittee shall maintain records of the monthly firing rates and CO, SO2, and NOx emissions at heaters H-101A, H-101B, and H-102.

(i) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.3.11, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.3.16 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.3.3, and D.3.10 , the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur emission rate, in pounds per hour, for No. 12 Pipe Still process heaters.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.3.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.3.6(a), the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC and to document compliance with Condition D.3.6(b), the Permittee shall submit reports as specified in Sections E.1, E.4, and E.13.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.3.8(a), the Permittee shall submit reports as specified in Sections E.1, and E.3.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.3.8(b), the Permittee shall submit reports as specified in Section E.6.

(g) In order to demonstrate compliance with Condition D.3.5, upon start-up of the H-101A, H-101B and H-102 heaters, the Permittee shall submit a quarterly summary of the monthly firing rates, and CO, NOx, and SO2 emissions for heaters H-101A, H-101B, and H-102 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(h) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.3.5 and D.3.11, the Permittee shall submit reports of excess SO2, NOx and CO emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.4 FACILITY OPERATION CONDITIONS - Sulfur Recovery Unit

Facility Description [326 IAC 2-7-5(15)]:

(d) The Sulfur Recovery Unit (SRU) Facility, identified as Unit ID 162, originally constructed in 1971 and expanded in 1981 and 1995, and rated at 600 long tons per day of sulfur and will be modified as part of the CXHO Project increasing the capacity to 1,300 long tons per day. The facility includes the following and may also include insignificant activities listed in Section A.4 of this permit:

(1) Three (3) three-stage Claus sulfur recovery trains, identified as A, B, and C, and two (2) additional three-stage Claus sulfur recovery trains installed after modification, identified as D and E trains.

(2) One (1) Beavon-Stretford tail gas unit (B/S TGU), a reduction system with a burner capacity of 24.3 MMBtu per hour, exhausting at stack S/V 162-02. The B/S TGU will be decommissioned as part of the CXHO project.

(3) One (1) tail gas unit (SBS TGU), an oxidation system with a burner capacity of 40 MMBtu per hour, exhausting at stack 162-04. The SBS TGU will be decommissioned as part of the CXHO project.

(4) One (1) caustic soda scrubbing tower to control sulfur dioxide emissions from the SBS TGU. The caustic soda scrubbing tower will be decommissioned as part of the CXHO project.

(5) One (1) cooling tower, identified as the SBS cooling tower, to remove sodium bisulfite from the caustic scrubbing tower exhaust stream, equipped with a high-efficiency mist eliminator, and exhausting at stack 162-05. The SBS cooling tower will be decommissioned as part of the CXHO project.

(6) Gas quenching and cooling towers other than the SBS cooling tower, to be decommissioned as part of the CXHO project.

(7) One (1) quench separator with mist eliminators, to be decommissioned as part of the CXHO project.

(8) One (1) gas cooler and water condenser with sulfur dioxide stripper, to be decommissioned as part of the CXHO project.

(9) Caustic soda storage tanks and sodium bisulfite storage tanks, and handling equipment to be decommissioned as part of the CXHO project.

(10) One (1) standby incinerator, used only in the event of an emergency, exhausting at stack S/V 162-01, to be decommissioned as part of the CXHO project.

(11) One (1) flare stack exhausting at stack S/V 162-03 which controls H_2S and VOC emissions during emergency situations, unit start-ups/shut-downs, and preparation of equipment for maintenance. Refinery or natural gas is used as a constant purge stream. Pilot gas is natural gas.

(12) One (1) modular degassing unit, which removes gases that are emitted during the cooling of molten sulfur. Removed gases are vented to the SBS TGU. Removed gases will be vented to the front end of Claus Trains D and/or E as part of the CXHO project.

(13) Two (2) modular degassing units, to be installed as part of the CXHO project, which remove gases that are emitted during the cooling of molten sulfur. The gases will be vented to the front-end of Claus Trains D and/or E as part of the CXHO project.

(14) Three (3) sulfur pits, (Sulfur Pits A, B, and C) used to store molten sulfur with their vent stacks routed to the B/S TGU and/or the SBS. As part of the CXHO project, the vents from the sulfur pits A, B and C will be routed to either COT 1 and/or COT 2.

(15) Two (2) sulfur pits (Sulfur Pits D and E), to be installed as part of the CXHO project, used to store molten sulfur and the vents routed to either COT 1 and/or COT 2.

(16) One (1) sour water tank, identified as TK-431, with a maximum storage capacity of 845,600 gallons and used to store a material that has a vapor pressure of less 0.5 psia. The tank was constructed in 1985 and is equipped with an external floating roof.

(17) One (1) sour water storage tank, identified as TK-410, permitted in 2006, having a maximum storage capacity of 4,351.200 gallons and equipped with an external floating roof. The maximum true vapor pressure of the material stored in this tank is less than 0.5 psia.

(18) Two (2) Claus Offgas Treaters (COT), identified as COT1 and COT2, to be installed as part of the CXHO project, thermal oxidation systems which combust natural gas, each rated at 72 mmBTU/hr, equipped with SO2 and CO CEMS, exhausting at stacks S/V 162-06 and 162-07.

(19) Two (2) sulfur storage tanks, identified as SH-1 and SH-2, each with a maximum storage capacity of 1,008,000 gallons and used to store molten sulfur exhausting to stacks S/V 163-09 and 162-10. These tanks will be constructed as part of the CXHO Project and are both fixed roof tanks controlled by a caustic scrubber.

<u>Main Operating Scenario Pre-CXHO:</u>

Approximately 80% of tail gases from the three trains are sent to the B/S TGU, with the remainder sent to the SBS TGU.

Alternate Operating Scenario #1 Pre CXHO:
One train and the B/S TGU are not operate. Tail gases from the other two trains are sent to the SBS TGU.

Alternate Operating Scenario #2 Pre CXHO:
The B/S TGU is not operated. Tail gases from the three trains are sent to the SBS TGU.

Alternate Operating Scenario #3 Pre CXHO:
The SBS TGU is not operated. Tailgases from the three trains are sent to the B/S TGU.

Main Operating Scenario Post CXHO:
The tail gases from the five trains are sent to both of the COTs.

Alternate Operating Scenario #1 Post-CXHO:

One of the COTs is not operated and the tail gases from the five trains are sent to the other COT.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.4.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2),), particulate matter emissions from SBS TGU (until shutdown), each of the two (2) offgas treaters/thermal oxidizers identified as COT1 and COT2, and the SBS cooling tower (until shutdown) shall not exceed 0.03 grains per dry standard cubic foot.

D.4.2.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), until it is shutdown, the PM10 emissions from the B/S TGU shall not exceed 0.0075 lb/MMBTU and 0.182 lb/hr:

(b) Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the PM10 emissions from the Sulfur Recovery Unit Incinerator, until it is shutdown, shall not exceed 0.0075 lb/MMBTU and 0.285 lb/hr.

D.4.2.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), until it is shutdown, the filterable PM10 emissions from each of the following units shall not exceed the following:

Emission Unit	PM_{10} Limit (lbs/MMBtu)	PM_{10} Limit (lbs/ton of Feed)	PM_{10} Limit (lbs/hour)
Sulfur Recovery Unit Incinerator	0.004	None	0.090
Beavon Stretford Tail Gas Unit (B/S TGU)	None	0.110	0.103

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.4.2.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP), until the B/S TGU and Sulfur Recovery Unit Incinerator are shutdown. Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.4.3 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

(a) Pursuant to 326 IAC 7-4.1-3(a)(15), (16) and (17), emissions from the following Sulfur Recovery Unit process units shall comply with the following sulfur dioxide emission limitations:

Unit Description	SO_2 Emission Limitation (lbs/MMBtu)	SO_2 Emission Limitation (lbs/hour)
Sulfur Recovery Unit Incinerator (until shutdown)	0.033	1.25
Beavon Stretford Tail Gas Unit (B/S TGU) (until shutdown)	None	53.10 Total Reduced Sulfur calculated as SO_2
Sodium Bisulfite Tail Gas Unit (SBS TGU) (until shutdown)	None	9.0

(b) Pursuant to 326 IAC 7-4.1-1, the offgas treaters/thermal oxidizers identified as COT1 and COT2 shall burn natural gas only as supplemental fuel.

D.4.4 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR and Emission Offset [326 IAC 2-3] Minor Limit

(a) Pursuant to Construction Permit 089-3323-00003, issued December 14, 1994:

(1) Emissions of TRS calculated as SO_2 from the B/S TGU (until shutdown) shall not exceed 232.6 tons per twelve (12) consecutive month period.

(2) Emissions of TRS calculated as SO_2 from the B/S TGU (until shutdown) shall be limited to 300 parts per million by volume (ppmv).

(3) The following emission units shall remain inoperative unless new approval is obtained:

(A) Propane Dewaxing Unit

(B) #1, #2, and #3 Asphalt Oxidizers

(C) The Butamer Unit

(D) The F-7 Furnace to the Isomerization Unit

(E) The #1 Power Station Boiler #1

(b) Pursuant to SSM 089-13846-00003, issued on June 27, 2001, emissions of SO_2 at 0% excess air from the SBS TGU (until shutdown) shall not exceed 39.4 tons per twelve (12) consecutive month period.

Compliance with conditions (a) and (b) above shall render~~s~~ the requirements of 326 IAC 2-3 (Emission Offset) not applicable.

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(c) The PM and PM-10 emissions from COT1 and COT2 shall not exceed 0.0019 and 0.0075 pounds per million BTU, respectively.

(d) The VOC emissions from COT1 and COT2 shall not exceed 0.0054 pounds per million BTU.

(e) The combined SO2 emissions from COT1 and COT2 shall not exceed 194.8 tons per 12 consecutive month period, with compliance determined at the end of each month.

(f) The combined CO emissions from COT1 and COT2 shall not exceed 55.0 tons per 12 consecutive month period, with compliance determined at the end of each month.

(g) The NOx emissions from COT1 and COT2 shall not exceed 0.08 pounds per million BTU.

(h) The Permittee shall comply with the following firing rate limit:

Unit ID	Firing Rate (10^3 mmBTU) per 12 consecutive month period
COT1 and COT2 (total)	1261.4

(i) The B/S TGU, SBS TGU, and SBS Cooling tower shall be permanently shutdown prior to the completion of the CXHO project.

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.4.5 New Source Performance Standards [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(2), the Permittee shall comply with the requirements in Section E.2 for the SBS TGU (until shutdown), COT1 and COT2 offgas treaters/thermal oxidizers and B/S TGU (until shutdown).

D.4.6 Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

D.4.7 Wastewater [326 IAC 12] [40 CFR 60, Subpart QQQ]

Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

D.4.8 Requirements for 40 CFR Part 63, Subpart UUU

Pursuant to 40 CFR 63, Subpart UUU, the Sulfur Recovery Unit and associated bypass lines shall comply with the requirements of Section E.10.

Compliance Determination Requirements

D.4.9 Operating Requirements

(a) Pursuant to permit SSM 089-13846-00003 issued June 27, 2001 as amended by Administrative Amendment 089-15525-00003 issued April 15, 2002, the Permittee shall re-route all NSPS SRP sulfur pit emissions such that they are treated, monitored, and included as part of the emissions of the SRU subject to the NSPS Subpart J limit for SO2.

(b) Compliance with the limits in Conditions D.4.4(c),(d) and (g) shall be demonstrated as specified in Condition D.0.3.

D.4.10 Testing Requirements [326 IAC 2-7-6(1), (6)] [326 IAC 2-1.1-11]

Within 3 months of the issuance of this permit and in order to demonstrate compliance with Condition D.4.1, the Permittee shall perform testing of the total dissolved solids (TDS) in the SBS cooling tower utilizing methods as approved by the Commissioner. The SBS tower will be deemed in compliance with 326 IAC 6.8-1-2 provided that the total dissolved solids in the cooling tower water do not exceed 3300 ppmv. This test shall be repeated at least once every three months from the date of this valid compliance demonstration.

D.4.11 Operating Requirement

Until the SRU incinerator is shutdown:

Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitation for the SRU incinerator in Condition D.4.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

D.4.12 Continuous Emissions Monitoring

In order to demonstrate compliance with Condition D.4.4, the SO2 and CO continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for COT1 and COT2 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.4.13 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.4.14 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Condition D.4.3, the Permittee shall maintain daily records of the following for the SRU incinerator (until shutdown) for each day that the unit is operated:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.4.2, the Permittee shall maintain records for the SRU (until shutdown) as specified in the Continuous Compliance Plan.

(c) Pursuant to 326 IAC 7-4.1-3(b)(1)(C) and to document compliance with Condition D.4.3, the Permittee shall maintain daily records of the following for the B/S TGU (until shutdown):

(1) total reduced sulfur concentration,

(2) hydrogen sulfide concentration, and

(3) calculated stack gas flow rates.

(d) Pursuant to 326 IAC 7-4.1-3(b)(1)(D) and to document compliance with Condition D.4.3, the Permittee shall maintain daily records of the following for the SBS TGU (until shutdown):

(1) sulfur dioxide concentration, and

(2) stack gas flow rate.

(e) To document compliance with Condition D.4.4(a), the Permittee shall keep the following records for the B/S TGU (until shutdown):

(1) one-minute block averages from the TRS CEM, and

(2) average TRS emission rates, calculated as SO_2, per twelve (12) consecutive month period.

(f) To document compliance with Conditions D.4.4(b), the Permittee shall keep the following records for the SBS TGU (until shutdown):

(1) one-minute block averages from the SO_2 CEM, and

(2) average SO_2 emission rate per twelve (12) consecutive month period.

(g) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.4.5, the Permittee shall maintain the records specified in Section E.2.

(h) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.4.6, the Permittee shall keep records as specified in the LDAR plan.

(i) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.4.7, the Permittee shall keep records as specified in Section E.6.

(j) Pursuant to 326 IAC 8-9-6 (Volatile Organic Liquid Storage Vessels), the Permittee shall maintain records of the following information for storage tank TK-431:

(1) The vessel identification number.

(2) The vessel dimensions.

(3) The vessel capacity.

The Permittee shall keep all records as described in (1) through (3) for the life of the vessel.

(k) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.4.12, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.4.15 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Condition D.4.3, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the following information:

(1) average daily sulfur emission rate, in pounds per hour, for the SRU incinerator;

(2) the average daily sulfur dioxide emission rate for the incinerator and B/S TGU, in terms of pounds per hour of sulfur dioxide; and

(3) the average daily total reduced sulfur emission rate, calculated as sulfur dioxide, for the SBS TGU in pounds per hour.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.4.5, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.4.6, the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the standard operating procedures (SOP) submitted to OAQ for the continuous emission monitors, updates shall be submitted biennially.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.4.7, the Permittee shall submit reports as specified in Section E.6.

(f) Until the B/S TGU and SBS are shutdown, a quarterly summary of the information to document compliance with Condition D.4.4 shall be submitted to the address listed in Section C - General Reporting Requirements, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

(g) Pursuant to 40 CFR 63, Subpart UUU and to demonstrate compliance with Condition D.4.8, the Permittee shall submit to IDEM, OAQ the documents specified in Condition E.10.

(h) In order to demonstrate compliance with Condition D.4.4, upon start-up of COT 1 and/or COT 2, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 and CO emissions at COT1 and COT2 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(i) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.4.4 and D.4.12, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments.

SECTION D.5 FACILITY OPERATION CONDITIONS - Vapor Recovery Units 100 and 200

Facility Description [326 IAC 2-7-5(15)]:

(e) (1) Vapor Recovery Unit 100 (VRU-100) identified as Unit ID 241, and Vapor Recovery Unit 200 (VRU-200) identified as Unit ID 231, permitted for turnaround (TAR) in 2008 to repair or replace tower trays and increase existing pumping and cooling capacities. Gasoline and lighter products from the FCUs are separated in the VRUs using a series of distillation towers. The VRUs are connected to flare stack S/V 241-01, the VRU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes leaks from process equipment including one (1) compressor (identified as J-3E located at VRU-100), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system. The facility may ~~also~~ include insignificant activities listed in Section A.4 of this permit.

(2) As part of the VRU 100/200 Whiting Atmospheric Relief Project (WARP), permitted in 2008, the pressure relief discharges that vented to the existing VRU 100/200 vent stack are being re-routed to the VRU flare.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.5.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

D.5.2 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.5.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) After the startup of the New Coker (#2 Coker), the vent stack for VRU 100 and VRU 200 shall be permanently shutdown and the pressure relief discharges that were routed to the vent stack will be routed to the VRU flare.

Compliance Determination Requirements

D.5.4 Operating Requirement

In order to demonstrate compliance with Condition D.5.3, following the startup of New Coker (#2 Coker), the pressure relief discharges from VRU 100 and VRU 200 shall be routed to the VRU flare. The flare must be operated with a flame present at all times that VRU 100 or VRU 200 is in operation.

Compliance Monitoring Requirements

D.5.5 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

(b) Prior to start-up of VRU 100 and VRU 200, BP shall make a determination as to whether 40 CFR Part 60, Subpart GGGa has been triggered by the changes made as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.5.6 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.5.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.5.1(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.5.2, the Permittee shall keep records as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.5.2, the Permittee shall keep records as specified in Section E.6.

D.5.7 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.5.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.5.1(b), the Permittee shall submit reports as specified in Section E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.5.2, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.5.2, the Permittee shall submit reports as specified in Section E.6.

SECTION D.6 FACILITY OPERATION CONDITIONS - Vapor Recovery Units 300 and 400

Facility Description [326 IAC 2-7-5(15)]:

(f) (A) The Vapor Recovery Unit 300 (VRU 300), identified as Unit ID 150. Light ends and naphtha are separated in the VRU using a series of distillation towers. This unit is connected to flare stack S/V 241-01, the VRU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) off-gas knock out drum (D-400) which exhausts to flare stack S/V 241-01.

(2) Leaks from process equipment, including two (2) compressors (identified as K-340 and K-351), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation system.

(B) Vapor Recovery Unit VRU 400 for the New Coker (#2 Coker), permitted in 2008, to be installed as part of the CXHO project.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.6.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC for VRU 300 and VRU 400 from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems for VRU 300 and VRU 400.

(c) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, for VRU 400, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.6.2 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.6.3 Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Section E.1 for the control of miscellaneous process vent emissions from the off gas knock-out drum (D-400).

This miscellaneous process vent is routed to the VRU Flare. Additional requirements for the VRU Flare are included in Section D.35.

Compliance Monitoring Requirements

D.6.4 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.6.5 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.6.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions D.6.1(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions D.6.3, the Permittee shall keep records as specified in Section E.1.

(d) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.6.2, the Permittee shall keep records as specified in Sections E.1 and E.3.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.6.2, the Permittee shall keep records as specified in Section E.6.

D.6.6 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.6.2(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions D.6.3(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.12.

(c) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions D.6.3, the Permittee shall submit reports as specified in Section E.1.

(d) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.6.2, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.6.2, the Permittee shall submit reports as specified in Section E.6.

SECTION D.7 FACILITY OPERATION CONDITIONS - Alkylation Unit

Facility Description [326 IAC 2-7-5(15)]:

(g) The Alkylation Unit, identified as Unit ID 140, combines isobutane with butylenes and propylenes to produce alkylate. The alkylate, a high octane naphtha, is blended into gasoline. This unit was built in 1961 and expanded in 1989. This unit is connected to flare stack S/V 140-01, the Alky Flare, to control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) off gas knock-out drum (D-22), which exhausts to flare stacks S/V 140-01.

(2) One (1) spent acid stripper drum (D-13), which exhausts to flare stacks S/V 140-01.

(3) One (1) spent caustic drum (D-32), which exhausts to flare stacks S/V 140-01.

(4) Leaks from process equipment, including two (2) compressors (identified as K-1 and K-1A), valves, pumps, pressure relief devices, sampling connection systems, and instrumentation system.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.7.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGG] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, 40 CFR 60, Subpart GGG and Permit CP 089-10499-00003, issued February 10, 1999, the Permittee shall comply with the requirements specified in Sections E.1, E.4 and E.13 for equipment leaks of VOC and HAP from the compressor and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC and HAP service. Pursuant to 40 CFR 63.640(p), equipment that is subject to both 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC are required to comply only with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.7.2 Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Section E.1 for the control of miscellaneous process vent emissions from the off gas knock-out drum (D-22) and the spent acid stripper drum (D-13).

These miscellaneous process vents are routed to the Alky Flare. Additional requirements for the Alky Flare are included in Section D.37.

D.7.3 Wastewater/Waste Streams [326 IAC 12] [40 CFR 60, Subpart QQQ]

Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems subject to 40 CFR 60, Subpart QQQ.

Compliance Monitoring Requirements

D.7.4 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.7.5 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.7.1, the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 60, Subpart GGG and to document compliance with Conditions D.7.1(b), the Permittee shall keep records as specified in Sections E.1, E.4, and E.13.

(c) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions D.7.2, the Permittee shall keep records as specified in Sections E.1.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.7.3, the Permittee shall keep records as specified in Section E.6.

D.7.6 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.7.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 60, Subpart GGG and to document compliance with Conditions D.7.1(b), the Permittee shall submit reports as specified in Sections E.1, E.4 and E.13.

(c) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions D.7.2, the Permittee shall submit reports as specified in Section E.1.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.7.3, the Permittee shall submit records as specified in Section E.6.

SECTION D.8 FACILITY OPERATION CONDITIONS - Propylene Concentration Unit

Facility Description [326 IAC 2-7-5(15)]:

(h) The Propylene Concentration Unit (PCU), identified as Unit ID 145, purifies propylene for sale to chemical plants and eventual manufacture into polypropylene plastic. This unit also has a treating system, which purifies propane. This unit is connected to flare stack S/V 140-01 (the Alky Flare). The flare controls VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes a caustic degassing drum (D-100) that is vented to flare stack S/V 140-01 and leaks from process equipment, including one compressor (identified as k-104), pumps, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation system. This facility may include insignificant activities listed in Section A.4 of this permit.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.8.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [3267 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Prior to start-up of the new coker (#2 Coker), BP shall make a determination as to whether 40 CFR Part 60 GGGa has been triggered by component changes made on the PCU as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

Compliance Monitoring Requirements

D.8.2 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.8.3 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.8.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.8.1(b), the Permittee shall keep records as specified in Section E.1 and E.4.

D.8.4 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.8.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.8.1(b), the Permittee shall submit reports as specified in Section E.1 and E.4.

SECTION D.9 FACILITY OPERATION CONDITIONS - Isomerization Unit

Facility Description [326 IAC 2-7-5(15)]:

(i) The Isomerization Unit (Isom), identified as Unit ID 210, was constructed in 1985 as a conversion of the No.2 Ultraformer. The Isomerization process converts low octane naphtha into high octane gasoline blending components. This unit is connected to flare stack S/V 220-04, the UIU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the CXHO Project, the ISOM heater H-1 will be modified by replacing several burners with larger burners, with rated capacity remaining at 190 MMBTU/hr. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit.

(1) One (1) natural gas, refinery gas, or liquified petroleum gas-fired Process Heater H-1, modified as part of CXHO, rated at 190 MMBtu/hr and vented to stack S/V 210-01.

(2) One (1) Flare Knock-out Drum (D-18) with emissions vented to vessel D-24, which exhausts to flare stack S/V 220-04.

(3) Leaks from process equipment, including one (1) compressor (identified as K1), pumps, valves, process drains and pressure relief devices.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.9.1.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), PM10 emissions from the ISOM H-1 (also known as No. 2 Isomerization Feed Heater) furnace shall not exceed 0.0075 lb/MMBTU and 1.416 lb/hr.

D.9.1.2 Lake County PM_{10} (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), filterable PM10 emissions from the H-1 Feed Heater Furnace shall not exceed 0.004 lb/MMBtu and 0.704 lb/hr.

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.9.1.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.9.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3(a)(5), sulfur dioxide emissions from the H-1 Feed Heater Furnace shall not exceed 0.034 lb/MMBtu and 6.46 pounds per hour.

D.9.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for ISOM heater H-1 upon issuance of Significant Permit Modification No. 089-25488-00453, unless otherwise specified:

(a) The emissions of NOx shall not exceed 0.275 pounds per million BTU.

(b) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(c) The emissions of SO2 shall not exceed 7.4 tons per 12 consecutive month period following the completion of the CXHO project.

(d) The emissions of PM and PM-10 each shall not exceed 0.0019 and 0.0075 pounds per million BTU, respectively.

(e) The emissions of CO shall not exceed 0.082 pounds per million BTU.

(f) The Permittee shall comply with the following limit on firing rate, following the completion of the CXHO project:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period
ISOM H-1	1342.03

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.9.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to SPM 089-15202-00003, issued on April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified E.2 for the H-1 Feed Heater Furnace.

D.9.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs)[326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [3267 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation system.

(c) Prior to start-up of the new coker (#2 Coker), BP shall make a determination as to whether 40 CFR Part 60 GGGa has been triggered by component changes made on the ISOM as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.9.6 Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Section E.1 to control miscellaneous process vent emissions from the off gas knock-out drum (D-18).

This miscellaneous process vent is routed to the UIU Flare. Additional requirements for the UIU Flare are included in Section D.35.

D.9.7 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

Compliance Determination Requirements

D.9.8 Operating Requirement

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002, fuel oil shall not be used as fuel for the H-1 Isom Process Heater.

D.9.9 Operating Requirement

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.9.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Compliance with the limits in D.9.3(a), (b), (d) and (e) shall be demonstrated as specified in in Condition D.0.3.

D.9.10 Continuous Emissions Monitoring

In order to demonstrate compliance with Condition D.9.3, the Total Reduced Sulfur continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limit from ISOM H-1 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements

D.9.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.9.12Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.9.2 and D.9.8, the Permittee shall maintain a daily record of the following for the H-1 Process Heater:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.9.1, the Permittee shall maintain records for the H-1 Feed Heater Furnace as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to demonstrate compliance with Condition D.9.4, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.9.5(a), the Permittee shall comply with equipment leak record keeping requirements as specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions D.9.5(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(f) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions D.9.6, the Permittee shall keep records as specified in Sections E.1.

(g) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.9.7, the Permittee shall keep records as specified in Section E.1 and E.3.

(h) In order to demonstrate compliance with Condition D.9.3, the Permittee shall maintain records of monthly firing rates and SO2 emissions for ISOM H-1.

(i) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.9.10, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.9.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.9.2 and D.9.8, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the H-1 Process Heater.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.9.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.9.5(a), the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.9.5(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.9.6, the Permittee shall submit reports as specified in Section E.1.

(f) In order to demonstrate compliance with Condition D.9.3, the Permittee shall submit a quarterly summary of monthly firing rates and SO2 emissions for ISOM H-1 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(g) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.9.3 and D.9.10, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.10 FACILITY OPERATION CONDITIONS - Aromatics Recovery Unit

Facility Description [326 IAC 2-7-5(15)]:

(j) The Aromatic Recovery Unit (ARU), identified as Unit ID 242, consists of the ARU 200 section and the ARU 300 section. The primary function is to remove light ends from naphtha to obtain a more desirable reforming feed. Its secondary function is to separate xylene, a chemical feedstock, from the Ultraformer product. The ARU utilizes a series of distillation towers to purify reformer feed and another set of towers to separate chemical feedstocks**.** The ARU includes the following process units and may include insignificant activities listed in Section A.4 of this permit.

(1) The following process heaters, which are fired with refinery gas, natural gas or liquified petroleum gas.

Heater Identification	Construction Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-200A	1978	249.5	242-01	None
F-200B	1978	249.5	242-02	None

(2) The ARU is connected to the 4UF flare stack, S/V 224-06. The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(3) Leaks from process equipment.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.10.1.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), PM_{10} emissions from the following ARU (Aromatic Recovery Unit) furnaces shall not exceed the following emission limitations:

Process Heater	PM_{10} Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
F-200A	0.0075	1.859
F-200B	0.0075	1.859

D.10.1.2 Lake County PM_{10} (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), filterable PM_{10} emissions from the following ARU combustion units shall not exceed the following emission limitations:

Process Heater	PM_{10} Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
F-200A	0.004	0.924
F-200B	0.004	0.924

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.10.1.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.10.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3(a)(8), sulfur dioxide emissions from the ARU combustion units, F-200A and F-200B, shall not exceed 0.035 pounds per MMBtu and a total for both F-200A and F200B of 17.47 pounds per hour.

D.10.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for heaters F-200A and F-200B upon issuance of Significant Permit Modification No. 089-25488-00453, unless otherwise specified:

(a) The emissions of NOx shall not exceed 0.275 pounds per million BTU.

(b) The emissions of CO shall not exceed 0.082 pounds per million BTU.

(c) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(d) The emissions of PM and PM-10 shall not exceed 0.0019 and 0.0075 pounds per million BTU, respectively.

(e) The Permittee shall comply with the following limits, following the completion of the CXHO project:

Unit ID	Firing Rate (10^3 mmBTU) per 12 month period	SO2 (tons per 12 consecutive month period)
F-200A	1264.94	7.0
F-200B	1264.94	7.0

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.10.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the F-200A and F-200B Process Heaters.

D.10.5 Equipment Leaks of Volatile Organic Compounds and Hazardous Air Pollutants[326 IAC 8-4-8] [36 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart J] [326 IAC 12][40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with Sections E.1 and E.4 for the equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation system.

(c) Pursuant to 40 CFR 61, Subpart J, the Permittee shall control benzene leaks from the pumps, pressure relief devices, sampling connection systems, open-ended valves, open-ended lines, and valves in accordance with requirements in Section E.5.

(d) Pursuant to 40 CFR 63.640(p), equipment that is subject to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart J is required only to comply with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

(e) Prior to start-up of the new coker (#2 Coker), BP shall make a determination as to whether 40 CFR Part 60 GGGa has been triggered by component changes made on the ARU as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.10.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil-water separators, and closed-vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

Compliance Determination Requirements

D.10.7 Operating Requirement

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002 and effective June 1, 2003, fuel oil shall not be used as fuel for the F-200A and F-200B Process Heaters.

D.10.8 Operating Requirement

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.10.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Compliance with the limits in D.10.3(a), (b), (c) and (d) shall be demonstrated as specified in Condition D.0.3.

D.10.9 Continuous Emissions Monitoring

In order to demonstrate compliance with Condition D.10.3(e), the Total Reduced Sulfur continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for F-200A and F-200B in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements

D.10.10 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.10.11 Recordkeeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and to document compliance with Conditions D.10.2, and D.10.7, the Permittee shall maintain a daily record of the following for the F-200A and F-200B Process Heaters:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.10.1, the Permittee shall maintain records for the process heater F-200A and F-200B as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to demonstrate compliance with Condition D.10.4, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.10.5(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) To demonstrate compliance with the equipment leak standards of 40 CFR 63, Subpart CC and to document compliance with Condition D.10.5(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(f) Pursuant to 40 CFR 61, Subpart J and to document compliance with Condition D.10.5(c), the Permittee shall keep records as specified in Section E.5.

(g) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.10.6, the Permittee shall keep reports as specified in Sections E.1 and E.3.

(h) In order to demonstrate compliance with Condition D.10.3, the Permittee shall maintain records of the monthly firing rates and SO2 emissions for F-200A and F-200B.

(i) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.10.9, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.10.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.10.2 and D.10.7, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the F-200A and F-200B Process Heaters.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.10.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.10.5(a), the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.10.5(b), the Permittee shall submit reports as specified in Section E.1 and E.4.

(e) Pursuant to 40 CFR 61, Subpart J and to document compliance with Condition D.10.5(c), the Permittee shall keep records as specified in Section E.5.

(f) Pursuant to 40 CFR 63, Subpart CC, 40 CFR 61, Subpart FF and to document compliance with Condition D.10.6, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(g) In order to demonstrate compliance with Condition D.10.3, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions at F-200A and F-200B to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(h) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.10.3 and D.10.9, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.11 FACILITY OPERATION CONDITIONS - Blending Oil Unit

Facility Description [326 IAC 2-7-5(15)]:

(k) The Blending Oil Unit (BOU), identified as Unit ID 250, uses hydrogen to convert sulfur to hydrogen sulfide and remove it from distillate and gas oil streams to meet product specifications. The hydrogen sulfide is sent to the Claus Trains for further processing. As part of the CXHO Project, the BOU heater F-401 will be modified by replacing burners. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) process Furnace F-401, constructed in1972, and modified as part of CXHO, which vents to stack ID SV250-01. The furnace is rated at 35 million Btu and is fired by natural gas, refinery gas or liquid petroleum gas.

(2) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.11.1.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), PM_{10} emissions from the F-401 BOU (Blending Oil Desulfurization) Process Furnace shall not exceed 0.0075 lb/MMBtu and 0.261 lb/hour.

D.11.1.2 Lake County PM_{10} (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), filterable PM_{10} emissions from the F-401 Process Furnace shall not exceed 0.004 lb/MMBtu and 0.130 lb/hour.

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.11.1.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.11.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from the F-401 Process Furnace shall not exceed 0.034 lb/MMBtu and 1.19 lbs/hour.

D.11.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for heater F-401 upon issuance of Significant Permit Modification No. 089-25488-00453, unless otherwise specified:

(a) The emissions of NOx shall not exceed 0.098 pounds per million BTU.

(b) The emissions of CO shall not exceed 0.082 pounds per million BTU.

(c) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(d) The emissions of PM and PM-10 each shall not exceed 0.0019 and 0.0075 pounds per million BTU, respectively.

(e) The Permittee shall comply with the following limits following the completion of the CXHO project:

Unit ID	Firing rate (10^3 mmBTU) per 12 month period	SO2 tons per 12 consecutive month period
F-401	201.48	1.1

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.11.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the F-401 Process Furnace.

D.11.5 Equipment Leaks of Volatile Organic Compounds (VOC) [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

D.11.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC, and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for drains systems subject to the 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for drain systems subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

Compliance Determination Requirements

D.11.7 Operating Requirement

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2003, effective June 1, 2003, fuel oil shall not be used as fuel for the F-401 Process Furnace.

D.11.8 Operating Requirement

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.11.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Compliance with limits in Condition D.11.3(a), (b), (c) and (d) shall be demonstrated as specified in Condition D.0.3.

D.11.9 Continuous Emissions Monitoring

In order to demonstrate compliance with Condition D.10.3, the Total Reduced Sulfur continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for F-401 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements

D.11.10 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.11.11 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.11.2, and D.11.7, the Permittee shall maintain a daily record of the following for the F-401 Process Furnace:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.11.1, the Permittee shall maintain records for the F-401 Process Furnace as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to demonstrate compliance with Condition D.11.4, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.11.5(a), the Permittee shall comply with equipment leak record keeping requirements as specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.11.6(a), the Permittee shall keep records as specified in Conditions E.1 and E.3.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.11.6(b), the Permittee shall keep records as specified in Section E.6.

(g) In order to demonstrate compliance with Condition D.11.3, the Permittee shall maintain the records of monthly firing rate and SO2 emissions at F-401.

(h) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.11.9, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.11.12Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.11.2 and D.11.7, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the F-401 Process Furnace.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.11.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.11.5, the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC 40 CFR 61, Subpart FF and to document compliance with Condition D.11.6(a), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.11.6(b), the Permittee shall submit reports as specified in Section E.6.

(f) In order to demonstrate compliance with Condition D.11.3, the Permittee shall submit a quarterly summary of the monthly firing rate and SO2 emissions at F-401 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(g) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.11.3 and D.11.9, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
    (A) Date of downtime.
    (B) Time of commencement.
    (C) Duration of each downtime.
    (D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.12 FACILITY OPERATION CONDITIONS - No. 2 Treatment Plant

Facility Description [326 IAC 2-7-5(15)]:

(l) No. 2 Treatment Plant, identified as unit 601, removes disagreeable odors from various naphtha streams using a catalytic process. This facility has only fugitive emissions and/or other emissions that are considered insignificant.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.12.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may request the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

D.12.2 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

Compliance Monitoring Requirements

D.12.3 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.12.4 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.12.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.12.1(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.12.2(a), the Permittee shall keep records as specified in Sections E.1 and E.3.11.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.12.2(b), the Permittee shall keep records as specified in Section E.6.

D.12.5 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8, and to document compliance with Condition D.12.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.12.1(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.12.2(a), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.12.2(b), the Permittee shall submit reports as specified in Section E.6.

SECTION D.13 FACILITY OPERATION CONDITIONS - No. 4 Treatment Plant

Facility Description [326 IAC 2-7-5(15)]:

(m) No. 4 Treatment Plant, identified as unit 602, removes disagreeable odors from various naphtha and distillate streams using a catalytic process. This facility has only fugitive emissions and/or other emissions that are considered insignificant. To be shutdown as part of the CXHO project.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.13.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, until shutdown, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, until shutdown, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

D.13.2 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, until shutdown, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil-water separators, and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, until shutdown, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), until shutdown a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

Compliance Monitoring Requirements

D.13.3 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, until shutdown the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.13.4 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.13.1(a), until shutdown the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.13.1(b), until shutdown the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.13.2(a), until shutdown the Permittee shall keep records as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.13.2(b), until shutdown the Permittee shall keep records as specified in Section E.6.

D.13.5 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.13.1(a), until shutdown the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.13.1(b), until shutdown the Permittee shall submit reports as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.13.2(a), until shutdown the Permittee shall submit reports as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.13.2(b), until shutdown the Permittee shall submit reports as specified in Section E.6.

SECTION D.14 FACILITY OPERATION CONDITIONS - Butane, Propane, and Propylene Storage and Loading Facilities

Facility Description:

(n) Butane, Propane and Propylene Storage and Loading Facilities, identified as Unit ID 604, includes the following sources of emissions and may also include insignificant activities listed in Section A.4 of this permit:

(1) One (1) butane storage cavern located in South Tank Field.

(2) Seven (7) pressurized butane storage spheres located southwest of the main Refinery near the J&L Tank Field with a capacity of 1,050,000 gallons each.

(3) Propane (LPG) storage caverns and above-grade pressurized storage vessels located near the J&L Tank Field.

(4) Propane (LPG) railcar loading facilities located near the J&L Tank Field. These can also be used for loading butane into railcars.

(5) Pressurized polymer grade propylene (PGP) and refinery grade propylene (RGP) storage vessels located at the north east end of the Refinery.

(6) Propylene truck and railcar loading facilities located at the north east end of the Refinery, with emissions vented to the PIB flare, which is owned and operated by INEOS USA, LLC (Plant I.D. 089-00076).

(7) One (1) LPG loading area flare stack having stack number S/V 604-01, installed in 1986, which is used as a safety device which burns any vented gases that might result from relieving pressure on equipment.

(8) Leaks from process equipment.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.14.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

D.14.2 General Conditions for Pressurized Storage Tanks

Pursuant to OP 000204, issued March 8, 1996 by the Hammond Department of Environmental Management, the Permittee shall comply with the following requirements for pressurized spheres 3944, 3945, 3946, 3947, 3948, 3949, and 3950:

(a) The VOC emissions from the pressurized storage spheres shall not exceed 24.0 tons per year.

(b) The Permittee shall not vent the spheres so as to exceed average operating hours of 2.71 hours per month or 32.5 hours per year.

Compliance Monitoring Requirements

D.14.3 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.14.4 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.14.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.14.1(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant to 326 IAC 8-4-3(d), the Permittee shall maintain the following records for all petroleum liquid storage vessels with a capacity greater than 39,000 gallons:

(1) the type of volatile petroleum liquid stored,

(2) the maximum true vapor pressure of the liquid stored, and

(3) the results of inspections performed on the storage vessels.

(d) Pursuant to OP 000204, issued March 8, 1996 and to demonstrate compliance with Condition D.14.2, the Permittee shall record and maintain a log of the numbers of minutes of venting of the seven (7) pressurized spheres.

D.14.5 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.14.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.14.1(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.

(c) Pursuant to OP 000204, issued March 8, 1996 and to demonstrate compliance with Condition D.14.2, the Permittee shall submit a monthly report of the number of minutes each tank is vented. The report required by this condition shall be submitted to HDEM and IDEM, OAQ.

SECTION D.15 FACILITY OPERATION CONDITIONS - No. 3 Ultraformer Unit

Facility Description [326 IAC 2-7-5(15)]:

(o) The No.3 Ultraformer Unit (No. 3 UF), identified as Unit ID 220, commissioned in 1958. The majority of the unit was shutdown in March 2007, including the H-1, H-2 and F-7 heaters, catalyst filled reactors and the internal scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation steps of the regeneration process. The unit consists of the C-2 Splitter Tower, the D-18 flare gas separator, D-24 knock-out drum and associated piping.

The No. 3 Ultraformer is connected to flare stack S/V 220-04, the UIU flare, to control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance and reactor regenerations. The No.3 Ultraformer includes the following sources of emissions and may include insignificant activities listed in Section A.4 of this permit.

(1) One (1) flare gas separator (D 18) with emissions vented to vessel D 24, which exhausts to flare stack S/V 220 04.

(2) Leaks from process equipment, including one (1) compressor (identified as K 1), pumps, pressure relief devices, sampling connection systems, open ended valves or lines, and instrumentation systems. (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.15.1 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Prior to the start-up of the new Coker (#2 Coker), permanently shutdown No. 3 Ultraformer, including 3UF heaters H-1, H-2, and F-7, and the 3UF Reformer, except for the C-2 splitter tower with associated piping and the D-18 flare gas separator.

Compliance with requirement to shutdown the No. 3 Ultraformer including the heaters H-1, H-2, and F-7 and Reformer, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.15.2 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

D.15.3 Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Section E.1 to control miscellaneous process vent emissions from the off gas knock-out drum (D-18).

This miscellaneous process vent is routed to the UIU Flare. Additional requirements for the UIU Flare are included in Section D.35.

D.15.4 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

Compliance Monitoring Requirements

D.15.5 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.15.5(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.15.5(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.15.6, the Permittee shall keep records as specified in Section E.1.

(d) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.15.7(a), the Permittee shall keep records as specified in Sections E.1 and E.3.11.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.15.7(b), the Permittee shall keep records as specified in Section E.6.

D.15.13 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.15.7(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.15.5(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.15.6, the Permittee shall submit reports as specified in Section E.1.

(d) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.15.7(a), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.15.7(b), the Permittee shall submit reports as specified in Section E.6.

SECTION D.16 FACILITY OPERATION CONDITIONS - No. 4 Ultraformer Unit

Facility Description [326 IAC 2-7-5(15)]:

(p) The No.4 Ultraformer Unit (no. 4 UF), identified as Unit ID 224, built in 1972, upgrades low-octane naphtha to gasoline blending material and chemical feedstocks. The front-end of the unit is a desulfurization section. The reforming section consists of a series of process furnaces and catalyst-filled reactors in which the naphtha is heated and converted from straight chain to aromatic compounds. The reactor products are separated by distillation for further processing or blending into gasoline. A new reactor will be installed as part of the CXHO project.The No. 4 Ultraformer includes the following sources of emissions and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Nine (9) process heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBTU/hr)	Stack Exhausted To	Emission Controls
F-1	68	224-01	None
F-8A	163	224-01	None
F-8B	163	224-01	None
F-2	286	224-02	None
F-3	242	224-03	None
F-4R	137	224-04	None
F-5	99	224-04	None
F-6	49	224-04	None
F-7	52	224-05	None

(2) One (1) flare (identified as the 4UF flare), exhausting at stack S/V 224-06. The 4UF flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance, and reactor regenerations.

(3) Six (6) catalyst-filled reactors, which are vented to flare stack S/V 224-06 during the initial catalyst depressuring and catalyst purging steps of the regeneration process.

(4) Leaks from process equipment, including two (2) compressors (identified as K-1 and K-7), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(5) One (1) caustic scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation process, which removes HAP emissions. The scrubber system includes:

(A) One (1) caustic scrubber exhausting to stack 224-07;

(B) One (1) carbon adsorption system used to treat waste scrubber liquor prior to disposal; and

(C) Caustic feed unloading, storage, and transfer equipment.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.16.1.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the Permittee shall not exceed the following PM_{10} emission limitations for the No. 4 UF (Ultraformer) process heaters:

Process Heater	PM_{10} Limit (lb/MMBTU)	PM_{10} Limit (lb/hour)
Stack serving F-1 furnace, F-8A (reboiler) and F-8B (reboiler)	0.0075	2.936
F-2 (preheater furnace)	0.0075	2.131
F-3 (no. 1 reheat furnace)	0.0075	1.803
Stack serving F-4 (no. 2 reheat furnace), F-5 (no. 3 reheat furnace) and F-6 (no. 4 reheat furnace)	0.0075	2.124
F-7	0.0075	0.387

D.16.1.2 Lake County PM_{10} (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), the Permittee shall not exceed the following filterable PM_{10} emission limitations for the No. 4 UF process heaters:

Process Heater	**PM_{10} Limit (lbs/MMBtu)**	**PM_{10} Limit (lbs/hour)**
stack serving F-1, F-8A and F-8B	**0.004**	**1.459**
F-2	**0.004**	**1.059**
F-3	**0.004**	**0.896**
stack serving F-4R, F-5 and F-6	**0.004**	**1.060**
F-7	**0.004**	**0.159**

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.16.1.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.16.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, the Permittee shall comply with the following SO_2 emission limitations for the No. 4 UF process heaters:

Process Heater Identification	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)

F-1	0.033	13.0 total
F-8A	0.033	
F-8B	0.033	
F-2	0.033	9.44
F-3	0.033	7.99
F-4R	0.033	9.41 total
F-5	0.033	
F-6	0.033	
F-7	0.033	1.72

D.16.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) For heaters F-1, F-8A, F-8B, F-2, F-3, F-4, F-5, F-6 and F-7, upon issuance of Significant Permit Modification No. 089-25488-00453, the emissions shall not exceed the following emissions limits:

Heater ID	NOx (lb/mmBTU)	CO (lb/mmBTU)	VOC(lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
F-1	0.098	0.082	0.0054	0.0019	0.0075
F-2	0.186	0.082	0.0054	0.0019	0.0075
F-3	0.275	0.082	0.0054	0.0019	0.0075
F-4R	0.275	0.082	0.0054	0.0019	0.0075
F-5	0.098	0.082	0.0054	0.0019	0.0075
F-6	0.098	0.082	0.0054	0.0019	0.0075
F-7	0.098	0.082	0.0054	0.0019	0.0075
F-8A	0.275	0.082	0.0054	0.0019	0.0075
F-8B	0.275	0.082	0.0054	0.0019	0.0075

(b) The Permittee shall comply with the following limits following the completion of the CXHO project:

Unit ID	Firing rate (10^3 mmBTU) per 12 month period	SO2 (tons per 12 consecutive month period)
F-1	259.30	1.4
F-8A	1,246.55	6.9
F-8B	1,246.55	6.9
F-2	1,488.32	8.2
F-3	1,576.80	8.7
F-4	847.97	4.7
F-5	427.49	2.4
F-6	190.09	1.1
F-7	317.11	1.8

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.16.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements in Section E.2 for the F-1, F-8A, F-8B, F-2, F-3, F-4, F-5, F-6, and F-7 Process Heaters.

D.16.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs)[326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(d) Prior to start-up of 4UF after the installation of the new reactor for the CXHO project, BP shall make a determination as to whether 40 CFR Part 60 GGGa has been triggered by the changes made as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.16.6 Requirements for 40 CFR Part 63, Subpart UUU

Pursuant to 40 CFR 63, Subpart UUU, the No. 4 Ultraformer Unit and associated bypass lines shall comply with the requirements of Section E.10.

D.16.7 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC, and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual wastewater drains systems and oil-water separators subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

Compliance Determination Requirements

D.16.8 Operating Requirement

Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the F-1, F-8A, F-8B, F-2, F-3, F-4R, F-5, F-6, and F-7 Process Heaters.

D.16.9 Operating Requirement

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.16.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Compliance with the limits in D.16.3(a) shall be demonstrated as specified in Condition D.0.3.

D.16.10 Continuous Emissions Monitoring

The Total Reduced Sulfur continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A and F-8B in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements

D.16.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.16.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.16.2, and D.16.8, the Permittee shall maintain a daily record of the following for the F-1, F-8A, F-8B, F-2, F-3, F-4, F-5, F-6, and F-7 Process Heaters:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.16.1, the Permittee shall maintain records for the Process Heaters F-1, F-8A, F-8B, F-2, F-3, F-4, F-5, F-6 and F-7 as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.16.4, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.16.5(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.16.5(b), the Permittee shall keep records as specified in Section E.1 and E.4.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.16.7(a), the Permittee shall keep records as specified in Sections E.1 and E.3.

(g) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.16.7(b), the Permittee shall keep records as specified in Section E.6.

(h) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition D.16.6, the Permittee shall keep records as specified in Section E.10.

(i) In order to demonstrate compliance with Condition D.16.3, the Permittee shall maintain records of monthly firing rates and SO2 emissions at F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, and F-8B.

(j) Pursuant to 326 IAC 3-5- 6 and to document compliance with Condition D.16.10, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.16.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.16.2, and D.16.8, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the F-1, F-8A, F-8B, F-2, F-3, F-4R, F-5, F-6, and F-7 Process Heaters.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.16.4, the Permittee shall submit to IDEM, OAQ the reports specified in Condition E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.16.5(a), the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.16.5(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.16.7(a), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.16.7(b), the Permittee shall submit reports as specified in Section E.6.

(g) Pursuant to 40 CFR 63, Subpart UUU and to demonstrate compliance with Condition D.16.6, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.10.

(h) In order to demonstrate compliance with Condition D.16.3, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions at heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, and F-8B to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(i) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.16.3 and D16.10, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
    (A) Date of downtime.
    (B) Time of commencement.
    (C) Duration of each downtime.
    (D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.17 FACILITY OPERATION CONDITIONS - Hydrogen Unit

Facility Description [326 IAC 2-7-5(15)]:

(q) The Hydrogen Unit (HU), identified as Unit ID 698, commissioned in 1993, produces 99+% pure hydrogen needed for the refinery hydrotreating processes. The HU produces high purity hydrogen by reacting steam with methane. The reaction is carried out by heating the mixture in a furnace and reacting it in the presence of a catalyst. The HU includes the following sources of emissions and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) natural gas, refinery gas or liquified petroleum gas fired B-501 Process Heater rated at 366.3 MMBTU/hr, which exhausts at stack S/V 698-01. The Process Heater is equipped with low-NO_x burners.

(2) One (1) DDU Flare exhausting at stack S/V 698-02, burning natural gas as the pilot gas, used to control VOC emissions during emergency situations, unit startups and shutdowns and depressuring equipment for maintenance.

(3) Leaks from process equipment.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.17.1.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), PM10 emissions from the HU (hydrogen unit) B-501 Process Heater shall not exceed 0.0075 lb/MMBTU and 2.729 lb/hr.

D.17.1.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), filterable PM10 emissions from the B-501 HU Process Heater shall not exceed 0.009 lb/MMBTU and 3.340 lbs/hour.

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.1.1.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.17.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from the B-501 process heater shall not exceed 0.033 lbs/MMBtu and 12.09 lbs/hour.

D.17.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

(a) Upon issuance of Significant Permit Modification No. 089-25488-00453, the emissions from B-501 shall not exceed the following limits:

Heater ID	NOx (lb/mmBTU)	CO (lb/mmBTU)	VOC(lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
B-501	0.0675	0.02	0.0054	0.0019	0.0075

(b) After the start-up of the new Coker (#2 Coker), the SO2 emissions from B-501 shall not exceed 15.5 tons per 12 consecutive month period, with compliance determined at the end of each month.

(c) After the start-up of the new Coker (#2 Coker), the firing rate at B-501 shall not exceed 2,809,332 million BTU per 12 consecutive month period, with compliance determined at the end of each month.

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.17.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

(a) Pursuant to Permit CP 089-2055-00003, issued March 12, 1992 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements in Section E.2 for the HU Process Heater B-501and DDU Flare. The requirements for the DDU Flare are included in Section D.35.

(b) To demonstrate compliance with paragraph (a) of this condition and as approved by the U.S. EPA on March 3, 1999, the Permittee shall comply with the following alternative compliance monitoring requirements for the B-501 process heater:

(1) The Permittee shall sample the fuel gas at the representative location once every eight hour shift (three times per day) during the unit's operation with no more than ten hours elapsing between each sampling event. H_2S concentration shall be determined using three gas detection tubes with a span of 0-5 ppm for each sampling event.

(2) The Permittee shall calculate the average of the gas detection tube readings for each sampling event.

(3) If the H_2S concentrations equal or exceed 5 ppm within one hour, the Permittee shall begin performing H_2S sampling and analysis every hour using three gas tubes with a span of 0-200 ppm.

(4) When three consecutive hours of sampling with the 0-200 ppm gas detection tubes indicate that the H_2S concentration is below 5 ppm, the Permittee may revert to sampling as provided in paragraph (b)(1) of this condition.

(5) If the H_2S concentration ever exceeds 80 ppm, the Permittee shall install and certify a H_2S CEM within 180 days, and in the mean time continue to follow this approved alternative monitoring method.

(6) The Permittee shall submit quarterly summary reports indicating all instances when the H_2S concentration equals or exceeds 80 ppm, the actual H_2S concentration, and the times the unit was not operational.

(7) The Permittee shall maintain records of the gas detection tube results used to prepare the quarterly reports on file for at least two (2) years.

(8) The Permittee must obtain written approval from the U.S. EPA, Region V prior to using gas detection tubes with a 0-15 ppm span.

D.17.5 Emission Offset and Prevention of Significant Deterioration [326 IAC 2-2] [326 IAC 2-3]

Pursuant to Permit CP 089-2055-00003 issued on March 12, 1992, the Permittee shall comply with the following emission limitations and operating conditions:

(a) Carbon Monoxide (CO) emissions from the B-501 Process Heater shall not exceed 0.02 lb/MMBTU.

(b) All compressor seals in volatile organic compound (VOC) service shall be purged and vented to the flare header.

(c) The Propane Dewaxing Unit and Asphalt Oxidizer Nos. 2 and 3 shall remain inoperative.

Compliance with these limits makes 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) and 326 IAC 2-3 (Emission Offset) not applicable.

D.17.6 Equipment Leaks of VOC and Hazardous Air Pollutants (HAPs)[326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGG] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.4, and E.13 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. Pursuant to 40 CFR 63.640(p), equipment that is subject to both 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC are required to comply only with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.17.7 Wastewater Requirements [326 IAC 12] [40 CFR 60, Subpart QQQ]

Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

Compliance Determination Requirements

D.17.8 Operating Requirement

Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the B-501 Process Heater.

D.17.9 Operating Requirement

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.17.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Compliance with the limits in D.17.3(a) shall be demonstrated as specified in Condition D.0.3.

D.17.10 Continuous Emissions Monitoring

The Total Reduced Sulfur continuous emission monitoring system (CEMS) for B-501 shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limit for B-501 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.17.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.17.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.17.2, and D.17.8, the Permittee shall maintain a daily record of the following for the B-501 process heater:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.17.1, the Permittee shall maintain records for Process Heater B-501 as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.17.4, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.17.6(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Condition D.17.6(b), the Permittee shall keep records as specified in Sections E.1, E.4, and E.13.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.17.7, the Permittee shall keep records as specified in Section E.6.

(g) In order to demonstrate compliance with Condition D.17.3, the Permittee shall maintain records of monthly firing rate and SO2 emissions at B-501.

(h) Pursuant to 326 IAC 3-5-6 and to demonstrate compliance with D.17.10, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.17.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.17.2, and D.17.8, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the B-501 process heater.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.17.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.17.6(a), the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Condition D.17.6(b), the Permittee shall submit reports as specified in Sections E.1, E.4, and E.13.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.17.7, the Permittee shall submit reports as specified in Section E.6.

(f) In order to demonstrate compliance with Condition D.17.3, the Permittee shall submit a quarterly summary of the monthly firing rate and SO2 emissions at heater B-501 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(g) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.17.3 and D.17.10, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
    (A) Date of downtime.
    (B) Time of commencement.
    (C) Duration of each downtime.
    (D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.18 FACILITY OPERATION CONDITIONS - Distillate Desulfurizer Unit

Facility Description [326 IAC 2-7-5(15)]:

(r) The Distillate Desulfurizer Unit (DDU), identified as Unit ID 700, commissioned in 1993, removes sulfur from petroleum distillates. Distillate feed is mixed with hydrogen, heated in process furnaces and passed over a catalyst bed to convert sulfur compounds to H_2S. The DDU includes the following emissions sources and may include insignificant activities listed in Section A.4 of this permit:

(1) Process Heater WB-301, rated at 64.8 MMBTU/hr and exhausting to stack S/V 700-01. The Process Heater is equipped with low-NO_x burners and burns natural gas, refinery gas, or liquified petroleum gas.

(2) Process Heater WB-302, rated at 83.7 MMBTU/hr and exhausting to stack S/V 700-02. The Process Heater is equipped with low-NO_x burners and burns natural gas, refinery gas, or liquified petroleum gas.

(3) Leaks from process equipment.

(4) The Distillate Desulfurization Unit is connected to the DDU Flare System. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns and depressuring equipment for maintenance.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.18.1.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the Permittee shall not exceed the following PM10 emission limitations for the DDU Process Heaters:

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
WB-301	0.0075	1.106
WB-302	0.0075	

D.18.1.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), the Permittee shall not exceed the following filterable PM10 emission limitations for the DDU Process Heaters:

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
WB-301	0.004	0.250
WB-302	0.004	0.240

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.18.1.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.18.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from the WB-301 and WB-302 process heaters shall each not exceed 0.033 lbs/MMBtu and the total emissions from both process heaters shall not exceed 4.24 lbs/hour.

D.18.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

(a) For heaters WB-301 and WB-302, upon issuance of Significant Permit Modification No. 089-25488-00453, the emissions shall not exceed the following emissions limits:

Heater ID	NOx (lb/mmBTU)	CO (lb/mmBTU)	VOC (lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
WB-301	0.035	0.04	0.0054	0.0019	0.0075
WB-302	0.030	0.04	0.0054	0.0019	0.0075

(b) The Permittee shall comply with the following limits, following the completion of the CXHO project:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO2 tons per 12 consecutive month period
WB-301	620.21	3.4
WB-302	488.81	2.7

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.18.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for WB-301; and WB-302 process heaters.

D.18.5 Emission Offset and Prevention of Significant Deterioration (PSD) [326 IAC 2-2] [326 IAC 2-3]

The Permittee shall comply with the following emission limitations and operating conditions:

(a) Prior to start-up of the new coker (#2 Coker), nitrogen Oxide (NO_x) emissions from the WB-301 and WB-302 Process Heaters shall not exceed 0.065 lb/MMBTU. This is equivalent to total NO_x emissions of 36.6 tons per year from the WB-301 and WB-302 Process Heaters.

(b) Pursuant to permit CP 089 2055 0003 issued on March 12, 1992, and amended on February 19, 1999, carbon Monoxide (CO) emissions from the WB-301 and WB-302 Process Heaters shall not exceed 0.04 lb/MMBTU. This is equivalent to total CO emissions of 22.5 tons per year from the WB-301 and WB-302 Process Heaters.

(c) Prior to start-up of the new coker (#2 Coker), the input of natural gas and natural gas equivalents to Process Heaters WB-301 and WB-302 shall be limited to a total of 1089.7 million cubic feet (MMcf) per twelve (12) consecutive month period, with compliance determined at the end of every month. For the purpose of determining compliance with this limit, every one (1.0) MMcf of refinery gas usage shall be considered equivalent to one (1.0) MMcf of natural gas usage.

(d) Pursuant to permit CP 089 2055 0003 issued on March 12, 1992, and amended on February 19, 1999, all compressor seals in volatile organic compound (VOC) service shall be purged and vented to the flare header.

(e) Pursuant to permit CP 089 2055 0003 issued on March 12, 1992, and amended on February 19, 1999, the Propane Dewaxing Unit and Asphalt Oxidizer Nos. 2 and 3 shall remain inoperative.

Compliance with these limits makes 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) and 326 IAC 2-3 (Emission Offset) not applicable.

D.18.6 Equipment Leaks of VOC and Hazardous Air Pollutants (HAPs)[326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGG] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.4, and E.13 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. Pursuant to 40 CFR 63.640(p), equipment that is subject to both 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC are required to comply only with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

(c) Prior to start-up of the new coker (#2 Coker), BP shall make a determination as to whether 40 CFR Part 60, Subpart GGGa has been triggered by component changes made on the DDU as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.18.7 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

Compliance Determination Requirements

D.18.8 Operating Requirement

Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the WB-301 and WB-302 Process Heaters.

D.18.9 Operating Requirement

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.18.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Compliance with limits in condition D.18.3(a) shall be demonstrated as specified in Condition D.0.3.

D.18.10 Continuous Emissions Monitoring

The Total Reduced Sulfur continuous emission monitoring system (CEMS) for WB-301 and WB-302 shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for WB-301 and WB-302 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13-Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.18.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.18.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.18.2, and D.18.8, the Permittee shall maintain a daily record of the following for the WB-301 and WB-302 process heaters:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.8.1, the Permittee shall maintain records for the WB-301 and WB-302 as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.18.4, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.18.6(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC and to document compliance with Condition D.18.6(b), the Permittee shall keep records as specified in Sections E.1, E.4, and E.13.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.18.7(a), the Permittee shall keep records as specified in Sections E.1 and E.3.

(g) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.18.7(b), the Permittee shall keep records as specified in Section E.6.

(h) In order to demonstrate compliance with Condition D.18.3, the Permittee shall maintain records of monthly firing rates and SO2 emissions at WB-301 and WB-302.

(i) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.18.10, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.18.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.18.2, and D.18.8, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the WB-301 and WB-302 process heaters.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.18.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.18.6(a), the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC and to document compliance with Conditions D.18.6(b), the Permittee shall submit reports as specified in Sections E.1, E.4, and E.13.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.18.7(a), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.18.7(b), the Permittee shall submit reports as specified in Section E.6.

(g) In order to demonstrate compliance with Condition D.18.3, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions at heaters WB-301 and WB-302 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(h) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.18.3 and D.18.10, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
    (A) Date of downtime.
    (B) Time of commencement.
    (C) Duration of each downtime.
    (D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.19 FACILITY OPERATION CONDITIONS - Cat Feed Hydrotreating Unit

Facility Description [326 IAC 2-7-5(15)]:

(s) The Cat Feed Hydrotreating Unit (CFHU), identified as Unit ID 171, built in 1982, removes sulfur from and improves the quality of gas oil feed to the Fluidized Cracking Units. The No. 4 Ultraformer Flare Stack, S/V 224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The CFHU is connected to the No. 4 Ultraformer flare stack. The flare is used to control VOC emissions, unit startups and shutdowns, and preparation of equipment for maintenance. The CFHU includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) Three (3) process heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBTU/hr)	Stack Exhausted To	Emission Controls
F-801 A/B	66.5	171-01	low-NO_x burners
F-801C	60.0	171-02	ultra low-NO_x burners

(2) Leaks from process equipment.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.19.1.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the PM10 from each stack serving CFHU (Cat Feed Hydrotreating Unit) Process Heaters F-801A, F-801B and F-801C shall not exceed 0.0075 lb/MMBTU and 0.943 lb/hr.

D.19.1.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), PM10 (filterable) emissions from the CFHU Process Heaters F-801A/B shall be limited to 0.004 lbs/MMBtu and 0.246 lbs/hour.

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.19.1.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.19.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from the CFHU Process Heaters shall be limited as follows:

Process Heater Identification	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)
F-801A/B	0.035	2.33
F-801C	0.035	2.1

D.19.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

(a) For heaters F-801A, F-801B, and F-801C, upon issuance of Significant Permit Modification No. 089-25488-00453, the emissions shall not exceed the following emissions limits:

Heater ID	NOx (lb/mmBTU)	CO (lb/mmBTU)	VOC(lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
F-801A	0.049	0.082	0.0054	0.0019	0.0075
F-801B	0.049	0.082	0.0054	0.0019	0.0075
F-801C	0.036	0.0001	0.0054	0.0019	0.0075

(b) The Permittee shall comply with the following limits following the completion of the CXHO project:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO2 tons per 12 consecutive month period
F-801A	215.5	1.2
F-801B	215.5	1.2
F-801C	215.5	1.2

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.19.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SSM 089-14630-00003, issued on November 30, 2001 and 40 CFR 60.104(1)(a), the Permittee shall comply with the requirements specified in Section E.2 for the F-801 A/B and F-801C process heaters.

D.19.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) 326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 12] [40 CFR 60, Subpart GGG]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.4, and E.13 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. Pursuant to 40 CFR 63.640(p), equipment that is subject to both 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC are required to comply only with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.19.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

Compliance Determination Requirements

D.19.7 Operating Requirement

(a) Pursuant to Permit SSM 089-14630-00003, issued on November 30, 2001, fuel oil shall not be used as fuel for the CFHU Heaters.

(b) Compliance with the limits in Condition D.19.3(a) shall be demonstrated as specified in Condition D.0.3.

D.19.8 Prevention of Significant Deterioration (PSD) [326 IAC 2-2]

Pursuant to SSM 089-14630-00003, issued on November 30, 2001 and SPM 089-18588-00453, issued July 15, 2004, the Permittee shall comply with the following requirement:

Nitrogen oxide emissions from Furnace F- 801C shall be controlled by ultra low-NO_x burners having an emission rate of 0.040 pounds per million Btu or less. This limit equates to a potential to emit 10.51 tons of nitrogen oxides per year for Furnace F-801C. This condition renders the requirements of PSD as not applicable for nitrogen oxides.

D.19.9 Continuous Emissions Monitoring

The Total Reduced Sulfur continuous emission monitoring system (CEMS) for F-801A, F-801B, and F-801C shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for F-801A, F-801B, and F-801C in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

D.19.10 Operating Requirement

Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.19.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

Compliance Monitoring Requirements

D.19.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.19.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.19.2, and D.19.7, the Permittee shall maintain a daily record of the following for the CFHU Process Heaters F-801A/B and F-801C:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.19.1, the Permittee shall maintain records for the F-801A/B process heater as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.19.4, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.19.5(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Condition D.19.5(b), the Permittee shall keep records as specified in Sections E.1, E.4, and E.13.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, and to document compliance with Condition D.19.6(a), the Permittee shall keep records as specified in Sections E.1 and E.3.11.

(g) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.19.6(b), the Permittee shall keep records as specified in Section E.6.

(h) In order to demonstrate compliance with Condition D.19.3, the Permittee shall maintain records of monthly firing rates at F-801A, F-801B, and F-801C, and monthly emissions of SO2 from F-801A, F-801B, and F-801C.

(i) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.19.9, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.19.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.19.2, and D.19.7, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the CFHU Process Heaters F-801A/B and F-801C.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Conditions D.19.4, the Permittee shall submit the records as specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.19.5(a), the Permittee shall submit reports as specified in the LDAR plan.5

(d) Pursuant to 40 CFR 63, Subpart CC, 40 CFR 63, Subpart GGG, and to document compliance with Condition D.19.5(b), the Permittee shall submit reports as specified in Sections E.1, E.4, and E.13.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.19.6(a), the Permittee shall submit records as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.19.6(b), the Permittee shall submit records as specified in Section E.6.

(e) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.19.3 and D.19.10, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
- (A) Date of downtime.
- (B) Time of commencement.
- (C) Duration of each downtime.
- (D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.20 FACILITY OPERATION CONDITIONS - Catalytic Refining Unit

Facility Description [326 IAC 2-7-5(15)]:

(t) The Catalytic Refining Unit (CRU), identified as Unit ID 201, which removes sulfur from petroleum naphthas and distillates. Naphtha or distillate feed is mixed with hydrogen, heated in process furnaces and passed over a catalyst bed inside one of two reactor trains, identified as D-114 and D-105, to convert sulfur compounds to hydrogen sulfide. Hydrogen sulfide is subsequently removed from the product by distillation followed by scrubbing with an amine. The CRU includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) Two (2) heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-101	72	201-01	Low-NO_x Burners
F-102A	60	201-02	Low-NO_x Burners

(2) The CRU is connected to the UIU flare stack, S/V 220-04. The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(3) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

Main Operating Scenario:
The CRU operates as a naphtha hydrotreater. Maximum production under this scenario is 27,000 barrels per day.

Alternative Operating Scenario:
The CRU operates as a distillate hydrotreater. Maximum production under this scenario is 40,000 barrels per day.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.20.1.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the Permittee must comply with the following PM10 emission limitations for the No. 1 CRU (also known as unit ID 201) feed preheaters:

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
F-101	0.0075	0.536
F-102A	0.0075	0.447

D.20.1.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), the Permittee must comply with the following filterable PM10 emission limitations for the CRU Process Heaters:

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
F-101	0.004	0.267
F-102A	0.004	0.290

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.20.1.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.20.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, the Permitted shall comply with the following SO_2 emission limitations for the CRU Process Heaters:

Process Heater Identification	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)
F-101	0.04	2.88
F-102A	0.04	2.40

D.20.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

(a) For heaters F-101 and F-102A, upon issuance of Significant Permit Modification No. 089-25488-00453, the emissions shall not exceed the following emissions limits:

Heater ID	NOx (lb/mmBTU)	CO (lb/mmBTU)	VOC(lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
F101	0.08	0.082	0.0054	0.0019	0.0075
F-102A	0.08	0.082	0.0054	0.0019	0.0075

(b) The Permittee shall comply with the following limits, following completion of the CXHO project:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO2 tons per 12 consecutive month period
F-101	208.49	1.2
F-102A	208.49	1.2

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.20.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements in Section E.2 for the F-101 and F-102A process heaters.

D.20.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGG]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements in Sections E.1, E.4, and E.13 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. Pursuant to 40 CFR 63.640(p), equipment that is subject to both 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC are required to comply only with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.20.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil-water separators, and closed-vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

D.20.7 Prevention of Significant Deterioration (PSD) [326 IAC 2-2]

Pursuant to SSM 089-15052-00453, issued November 17, 2003:

(a) Nitrogen Oxide emissions from Process Heater F-101 shall be controlled by low-NO_x burners having an emission rate of 0.080 pounds per million Btu heat input or less.

(b) Nitrogen Oxide emissions from Process Heater F-102A shall be controlled by low-NO_x burners having an emission rate of 0.080 pounds per million Btu heat input or less.

Compliance Determination Requirements

D.20.8 Operating Requirement

(a) Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the F-101 and F-102A Process Heaters.

(b) Compliance with the limits in Condition D.20.3(a) shall be demonstrated as specified in Condition D.0.3.

D.20.9 Continuous Emissions Monitoring

The Total Reduced Sulfur continuous emission monitoring system (CEMS) for F-101 and F-102A shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for F-101 and F-102 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of

Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

D.20.10 Operating Requirement

Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.20.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

Compliance Monitoring Requirements

D.20.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.20.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.20.2, and D.20.8, the Permittee shall maintain a daily record of the following for the F-101 and F-102A Process Heaters:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.20.4, the Permittee shall maintain the records as specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8, and to document compliance with Condition D.20.5(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.20.6, the Permittee shall keep records as specified in Sections E.1 and E.3.

(e) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Condition D.20.5(b), the Permittee shall keep records as specified in Sections E.1, E.4., and E.13.

(f) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.20.1, the Permittee shall maintain records for the Process Heaters F-101 and F-102A, as specified in the Continuous Compliance Plan.

(g) In order to demonstrate compliance with Condition D.20.3, the Permittee shall maintain records of monthly firing rates and SO2 emissions at F-101 and F-102A.

(h) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.20.9, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.20.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.20.2 and D.20.8, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the F-101 and F-102A Process Heaters.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.20.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.20.5(a), the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC, 40 CFR 63, Subpart GGG and to document compliance with Condition D.20.5(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.20.7, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(f) In order to demonstrate compliance with Condition D.20.3, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions at heaters F-101 and F-102A to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(g) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.20.3 and D20.9, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.21 FACILITY OPERATION CONDITIONS - Fluidized Catalytic Cracking Unit 500

Facility Description [326 IAC 2-7-5(15)]:

(u) The Fluidized Catalytic Cracking Unit (FCU) 500, constructed in 1945, identified as Unit ID 230 and rated at 115,000 barrels per day. This facility converts hydrocarbons that boil above 500°F into lower molecular weight products, which include gasoline and LPG. The cracking takes place as the gas oil and catalyst stream mix in the reactor. This process results in the catalyst being coated with coke, which is subsequently burned off in a regenerator. The FCU 500 includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) catalyst regenerator. Flue gas from the regenerator passes through an ammonia injection system, a waste heat recovery unit which generates steam, an Electrostatic Precipitator for particulate matter control, and is exhausted through stack S/V 230-01. The ammonia injection system includes aqueous ammonia injection and handling equipment. Aqueous ammonia is transferred from the FCU 600 SCR system's storage tanks.

(2) Three (3) catalyst storage bins, one each for spent, equilibrium, and fresh catalyst. Particulate emissions from the spent catalyst storage bin, identified as Bin F-52, are controlled by one (1) cyclone, which exhausts to stack S/V 230-03.

(3) One (1) flare exhaust at stack S/V 241-01 (VRU Flare). The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including two (2) compressors (identified as J-3D and J-3G), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system.

(5) As part of the FCU 500 WARP, per SSM 089-25484-00453, the existing FCU 500 blowdown stack is being shutdown and the pressure relief discharges that were vented to the blowdown stack will be routed to the VRU flare.

(6) The FCU 500 turnaround (TAR) project, per SSM 089- 25484-00453, for the repair or replacement of the power recovery turbine, and the air ring for the catalyst regenerator. The increases in emissions from FCU 500 TAR are already accounted for as CXHO project related emissions increases.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.21.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)), PM10 emissions from FCU 500 shall not exceed 1.22 pounds per thousand pounds of coke burned and 73.2 pounds per hour.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.21.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3 (formerly 326 IAC 7-4-1.1(c)), sulfur dioxide (SO_2) emissions from FCU 500 shall not exceed 750 pounds per hour.

D.21.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for FCU 500 after the start-up of the new Coker (#2 Coker):

(a) The emissions of NOx shall not exceed 228.6 tons per 12 consecutive month period, with compliance determined at the end of each month.

(b) The emissions of VOC shall not exceed 3.3 pounds per 1000 barrels of fresh feed used per 12 consecutive month period, with compliance determined at the end of each month.

(c) The emissions of SO2 shall not exceed 200.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) The emissions of PM and PM-10 shall not exceed 0.465 pounds per 1000 pounds of coke burned at FCU 500 per 12 consecutive month period, with compliance determined at the end of each month.

(e) The emissions of CO shall not exceed 147.2 tons per 12 consecutive month period, with compliance determined at the end of each month.

(f) The fresh feed used at FCU 500 shall not exceed 37.6 million barrels per 12 consecutive month period, with compliance determined at the end of each month.

(g) The coke burned at FCU 500 shall not exceed 669,191,000 pounds per 12 consecutive month period, with compliance determined at the end of each month.

(h) The FCU 500 blowdown stack shall be permanently shutdown and the pressure relief discharges that were routed to the blowdown stack will be routed to the VRU flare.

Compliance with the FCU 500 throughput limits and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, CO, SO2, PM and PM-10 for the CXHO project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.21.4 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Prior to start-up of the FCU 500 after the TAR project, BP shall make a determination as to whether 40 CFR 60, Subpart GGGa has been triggered by component changes made on the FCU 500 as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.21.5 Requirements for 40 CFR Part 63, Subpart UUU

Pursuant to 40 CFR 63, Subpart UUU, Fluidized Catalytic Cracking Unit 500 shall comply with the requirements specified in Section E.10.

D.21.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.21.7 Alternative Opacity Requirements [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3(a), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed 20%; however, opacity levels shall not exceed 60% for any six (6) minute averaging period. Opacity in excess of 20% shall not continue for more than two (2) six (6) minute averaging periods in any twenty-four (24) hour period.

(b) Pursuant to 326 IAC 5-1-3(b), when moving ashes from the fuel bed or furnace in the FCU 500 boiler blowing tubes, opacity may exceed 20% in any one (1) six (6) minute averaging period. However, the opacity shall not exceed 60% for any six (6) minute averaging period and opacity in excess of 20% shall not continue for more than one (1) six (6) minute averaging period in a sixty (60) minute period. The averaging period shall not be permitted for more than three (3) six (6) minute averaging periods in a twelve (12) hour period.

Compliance Determination Requirements

D.21.8 Operating Requirement

(a) Pursuant to SPM 089-15202-00003, issued on April 24, 2002 and SPM 089-18588-00453, issued July 15, 2004, carbon monoxide (CO) emissions shall not exceed 500 parts per million by volume, on a dry basis, based on 1-hour averages. The CO limits shall not apply during periods of startup, shutdown, or malfunction.

(b) Compliance with the limits in Condition D.21.3(b) and (d) shall be demonstrated as specified in Condition D.0.3.

In order to demonstrate compliance with Condition D.21.3, after the startup of the New Coker (#2 Coker):

(c) The pressure relief discharges that were routed to the FCU 500 blowdown stack shall be routed to the VRU flare. The flare must be operated with a flame present at all times that FCU 500 is in operation.

D.21.9 Continuous Emissions Monitoring

The NOx, CO, and SO2 continuous emission monitoring systems (CEMS) for FCU 500 shall be calibrated, maintained, and operated for determining compliance with NOx, CO, and SO2 emissions limits for FCU 500 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements

D.21.10 Inspection and Monitoring Requirements for the Electrostatic Precipitator [326 IAC 6.8-8-7]

Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(r)(2)), the Permittee shall maintain a Continuous Compliance Plan (CCP) for the ESP. The CCP shall include recording, inspection, and maintenance procedures in accordance with the requirements provided in 326 IAC 6.8-8-7(2)(A) and (B) (formerly 326 IAC 6-1-10.1(r)(2)(A) and (B)), including operating parameters to be monitored and the inspection and maintenance schedule to be followed. The Permittee shall inspect the ESP according to the schedule and procedures specified in the CCP. Pursuant to 326 IAC 2-7-5(1)(B)(ii), the inspection schedule records shall be available for inspection by IDEM, OAQ for up to five (5) years after the date of inspection.

D.21.11 Continuous Monitoring [326 IAC 3-5-1(e)] [326 IAC 6.8-8]

(a) Pursuant to SPM 089-15202-00003, issued on April 24, 2002, SPM 089-18588-00453, issued July 15, 2004, and to demonstrate compliance with Conditions D.21.2 and D.21.7, continuous monitoring systems shall be installed, certified, calibrated, maintained, and operated in accordance with the applicable requirements of 40 CFR 60.13 and the CCP, and operated at all times when FCU 500 is in operation to monitor and record the following for the FCU 500 flue gas:

(1) The Permittee shall monitor and record the hourly average CO concentration, on a dry basis. Process analyzers, calibrated in accordance with the manufacturer's recommendations, may be used for this purpose.

(2) The Permittee shall use a NO_x CEMS to monitor performance of the FCU 500 during the life of the Consent Decree 2:96 CV 095 RL and to report compliance with the terms and conditions of the Consent Decree.

(3) The Permittee shall use an SO_2 CEMS to monitor performance of the FCU 500 and to report compliance with the terms and conditions of the Consent Decree 2:96 CV 095 RL.

(b) Pursuant to 326 IAC 3-5 and 326 IAC 6.8-8-5(2) (formerly 326 IAC 6-1-10.1(p)(2)), the Permittee shall continuously monitor the opacity of exhaust gases from the catalyst regenerator stack at all times when the catalyst regenerator is in operation. The Permittee shall comply with the performance and operating specifications in 326 IAC 3-5-2, the certification process in 326 IAC 3-5-3, the operation procedures in 326 IAC 3-5-4, and the quality assurance requirements in 326 IAC 3-5-5 for the continuous opacity monitor.

(c) Pursuant to 326 IAC 6.8-8-5(2) (formerly 326 IAC 6-1-10.1(p)(2)), the Permittee shall continuously monitor coke burn off rate, in pounds per hour, as specified in the Continuous Compliance Plan (CCP).

D.21.12 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.21.13 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(B) and to document compliance with Condition D.21.2, the Permittee shall maintain daily records of the following:

(1) calculated coke burn off rate for FCU 500, and

(2) sulfur content of the coke.

(b) Pursuant to 326 IAC 3-5-6 and to document compliance with Conditions D.21.3, D.21.7 , D.21.9 and D.21.11, the Permittee shall keep the following records for the continuous opacity monitor and continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.21.4(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.21.4(b), the Permittee shall keep records as specified in Section E.1 and E.4.

(e) Pursuant to SPM 089-15202-00003, issued on April 24, 2002, and SPM 089-18588-00453, issued July 15, 2004, and to document compliance with Condition D.21.8, the Permittee shall maintain records of 1-hour average CO emissions.

(f) Pursuant to 326 IAC 6.8-8-3 and 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5), (q)(1), and (r)(2)) and to demonstrate compliance with Condition D.21.1, the Permittee shall maintain records for the FCU and ESP as specified in the Continuous Compliance Plan.

(g) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.21.6(a), the Permittee shall keep records as specified in Sections E.1 and E.3.

(h) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.21.6(b), the Permittee shall keep records as specified in Section E.6.

(i) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition D.21.5, the Permittee shall keep records as specified in Section E.10.

(j) In order to demonstrate compliance with Condition D.21.3, the Permittee shall maintain records of fresh feed usage at FCU 500 and the coke burned at FCU 500 each month.

(k) In order to demonstrate compliance with Condition D.21.3, the Permittee shall maintain records of monthly emissions of SO2, NOx, and CO from FCU 500.

D.21.14Reporting Requirements

(a) Pursuant to 326 IAC IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.21.2, the Permittee shall submit a report containing the average daily sulfur dioxide emission rate, in pounds per hour, for FCU 500 within thirty (30) days after the end of each calendar quarter.

(b) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.21.7 and D.21.11, the Permittee shall submit reports of excess opacity emissions within thirty (30) days of the end each of quarter in which excess emissions occur. Pursuant to 321 IAC 3-5-7, the reports shall include:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. The actual opacity of each averaging period for each period in excess of the opacity limit. If the exceedance occurs continuously beyond one (1) six (6) minute period, the Permittee shall report either the percent opacity for each six (6) minute period or the highest six (6) minute average opacity for the entire period.

(5) A summary itemizing the exceedances by cause.

(c) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the standard operating procedures (SOP) submitted to OAQ for the continuous opacity monitor, updates shall be submitted biennially.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.21.4(a), the Permittee shall submit reports as specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.21.4(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.

(f) To document compliance with Condition D.21.8 and D.21.3, the Permittee shall submit reports of excess emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission, in terms of 1-hr averages, and

(5) A summary itemizing the exceedances by cause.

(g) Pursuant to 40 CFR 63, Subpart UUU and to demonstrate compliance with Condition D.21.5, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.10.

(h) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.21.6(a), the Permittee shall subject reports as specified in Section E.1 and E.3.

(i) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.21.6(b), the Permittee shall submit reports as specified in Section E.6.

(j) In order to demonstrate compliance with Condition D.21.3, the Permittee shall submit quarterly reports for the fresh feed used and coke burned at FCU 500. The report submitted by the Permittee does require the certification by the “Responsible Official” as defined by 326 IAC 2-7-1(34).

(k) In order to demonstrate compliance with Condition D.21.3, the Permittee shall submit quarterly reports of monthly emissions of SO2, NOx, and CO from FCU 500. The report submitted by the Permittee does require the certification by the “Responsible Official” as defined by 326 IAC 2-7-1(34).

(l) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.21.3 and D.21.11, the Permittee shall submit reports of excess SO2, NOx, and CO emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(A) Date of downtime.

(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.22 FACILITY OPERATION CONDITIONS - Fluidized Catalytic Cracking Unit 600

Facility Description [326 IAC 2-7-5(15)]:

(v) The Fluidized Catalytic Cracking Unit (FCU) 600, constructed in 1946, identified as Unit ID 240 and rated at 80,000 barrels per day. This facility converts hydrocarbons that boil above 500 ^{o}F into lower molecular weight products, which include gasoline and LPG. The cracking takes place as the gas oil and catalyst stream mix in the reactor. This process results in the catalyst being coated with coke, which is subsequently burned off in a regenerator**.** The FCU 600 includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) catalyst regenerator. Flue gas from the regenerator passes through a waste heat recovery unit, which generates steam and an Electrostatic Precipitator for particulate matter control. The flue gas is then directed to a selective catalytic reduction (SCR) system, which chemically reduces nitrogen oxide emissions by reaction with injected ammonia, and is exhausted through stack S/V 240-01.

(2) Two catalyst storage bins, one each for equilibrium and fresh catalyst. (Spent catalyst is stored in Bin F-52, which is associated with FCU 500.)

(3) One (1) flare exhausting at stack ID S/V 230-02 (FCU Flare). The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including two (2) wet gas compressors (identified as J-3Dand J-3E), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system.

(5) As part of the FCU 600 WARP, per SSM 089-25484-00453 the existing FCU 600 blowdown stack is being shutdown and the pressure relief discharges that were vented to the blowdown stack are being re-routed to the FCU flare.

(6) The FCU 600 turnaround (TAR) project, per SSM 089-25484-00453 , for the repair or replacement of the main fractionator overhead condensers, the slurry and pump around system, unit pump replacement, FCU flare tip replacement, and additional controls to reduce plugging on the SCR. The increases in emissions from FCU 600 TAR are already accounted for as CXHO project related emissions increases.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.22.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)), PM10 emissions from FCU 600 shall not exceed 1.10 pounds per thousand pounds of coke burned and 55.0 pounds per hour.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.22.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide (SO_2) emissions from FCU 600 shall not exceed 437.50 pounds per hour.

D.22.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for FCU 600:

After the startup of the New Coker (#2 Coker), the Permittee shall comply with the following:

(a) The emissions of NOx shall not exceed 73.8 tons per 12 consecutive month period, with compliance determined at the end of each month.

(b) The emissions of VOC shall not exceed 3.3 pounds per 1000 barrels of fresh feed used per 12 consecutive month period, with compliance determined at the end of each month.

(c) The emissions of SO2 shall not exceed 190.0 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) The emissions of PM and PM-10 shall not exceed 0.35 pounds per 1000 pounds of coke burned at FCU 600 per 12 consecutive month period, with compliance determined at the end of each month.

(e) The emissions of CO shall not exceed 92.1 tons per 12 consecutive month period, with compliance determined at the end of each month.

(f) The fresh feed used at FCU 600 shall not exceed 24.09 million barrels per 12 consecutive month period, with compliance determined at the end of each month.

(g) The coke burned at FCU 600 shall not exceed 428,802,000 pounds per 12 consecutive month period, with compliance determined at the end of each month.

(h) The FCU 600 blowdown stack shall be permanently shutdown and with the exhaust routed to the FCU stack.

Compliance with the FCU 600 throughput limits and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

Compliance Determination Requirements

D.22.4 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Prior to start-up of the FCU 600 after the TAR project, BP shall make a determination as to whether 40 CFR 60, Subpart GGGa has been triggered by component changes made on the FCU 600 as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.22.5 Requirements for 40 CFR Part 63, Subpart UUU

Pursuant to 40 CFR 63, Subpart UUU, the Fluidized Catalytic Cracking Unit 600 and associated bypass lines shall comply with the requirements of Section E.10.

D.22.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil-water separators, and closed-vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

D.22.7 Operating Requirement

Pursuant to SPM 089-15202-00003, issued on April 24, 2002 and SPM 089-18588-00453, issued July 15, 2004:

(a) The Permittee shall use a selective catalytic reduction (SCR) system to reduce Nitrogen Oxide (NO_x) emissions.

(b) The carbon monoxide (CO) emissions shall not exceed 500 parts per million by volume, on a dry basis, based on 1-hour averages. The CO limit shall not apply during periods of startup, shutdown, and malfunction.

(c) Compliance with limits in Condition D.22.3(b) and (d) shall be demonstrated as specified in Condition D.0.3.

In order to demonstrate compliance with Condition D.22.3, after the startup of the New Coker (#2 Coker):

(d) The pressure relief discharges that were routed to the FCU 600 blowdown stack shall be routed to the FCU flare. The flare must be operated with a flame present at all times that FCU 600 is in operation.

D.22.8 Alternative Opacity Requirements [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3(a), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed 20%; however, opacity levels shall not exceed 60% for any six (6) minute averaging period. Opacity in excess of 20% shall not continue for more than two (2) six (6) minute averaging periods in any twenty-four (24) hour period.

(b) Pursuant to 326 IAC 5-1-3(b), when moving ashes from the fuel bed or furnace in the FCU 500 boiler blowing tubes, opacity may exceed 20% in any one (1) six (6) minute averaging period. However, the opacity shall not exceed 60% for any six (6) minute averaging period and opacity in excess of 20% shall not continue for more than one (1) six (6) minute averaging period in a sixty (60) minute period. The averaging period shall not be permitted for more than three (3) six (6) minute averaging periods in a twelve (12) hour period.

D.22.9 Continuous Emissions Monitoring

The NOx, CO, and SO2 continuous emission monitoring systems (CEMS) for FCU 600 shall be calibrated, maintained, and operated for determining compliance with NOx, CO, and SO2 emissions limits for FCU 600 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements

D.22.10 Inspection and Monitoring Requirements for the Electrostatic Precipitator [326 IAC 6.8-8-7]

Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(r)(2)), the Permittee shall maintain a Continuous Compliance Plan (CCP) for the ESP. The CCP shall include recording, inspection, and maintenance procedures in accordance with the requirements provided in 326 IAC 6.8-8-7(2)(A) and (B) (formerly 326 IAC 6-1-10.1(r)(2)(A) and (B)), including operating parameters to be monitored and the inspection and maintenance schedule to be followed. The Permittee shall inspect the ESP according to the schedule and procedures specified in the CCP. Pursuant to 326 IAC 2-7-5(1)(B)(ii), the inspection schedule records shall be available for inspection by IDEM, OAQ for up to five (5) years after the date of inspection.

D.22.11 Continuous Monitoring [326 IAC 3-5][326 IAC 6.8-8]

(a) Pursuant to SPM 089-15202-00003, issued on April 24, 2002, SPM 089-18588-00453, issued July 15, 2004, and to demonstrate compliance with Condition D.22.9(b), the Permittee shall:

(1) The Permittee shall use NOx CEMS to monitor performance of FCU 600 and to report compliance with the terms and compliance with the terms and conditions of Consent Decree 2:96 CV 095 RL.

(2) The Permittee shall measure and record the hourly average concentration, on a dry basis, of carbon monoxide in the exhaust gas stream. Process analyzers, calibrated in accordance with the manufacturer's recommendations, may be used for this purpose.

(3) The Permittee shall use a SO_2 CEMS to monitor performance of FCU 600 and to report compliance with the terms and conditions of Consent Decree 2:96 CV 095 RL.

(b) Pursuant to 326 IAC 3-5 and 326 IAC 6.8-8-5(2) (formerly 326 IAC 6-1-10.1(p)(2)), the Permittee shall continuously monitor the opacity of exhaust gases from the catalyst regenerator stack at all times when the catalyst regenerator is in operation. The

Permittee shall comply with the performance and operating specifications in 326 IAC 3-5-2, the certification process in 326 IAC 3-5-3, the operation procedures in 326 IAC 3-5-4, and the quality assurance requirements in 326 IAC 3-5-5 for the continuous opacity monitor.

(c) Pursuant to 326 IAC 6.8-8-5(2) (formerly 326 IAC 6-1-10.1(p)(2)), the Permittee shall continuously monitor coke burn off rate, in pounds per hour, as specified in the Continuous Compliance Plan (CCP).

D.22.12 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.22.13 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(C) and to document compliance with Condition D.22.2, the Permittee shall maintain daily records of the following:

(1) calculated coke burn off rate for FCU 600, and

(2) sulfur content of the coke.

(b) Pursuant to 326 IAC 3-5-6 and to demonstrate compliance with Conditions D.22.8, D.22.9 and D.22.11, the Permittee shall keep the following records for the continuous opacity monitor and continuous emission monitors:

(1) One-minute block averages;

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities,

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.22.4(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.22.4(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(e) Pursuant to SPM 089-15202-00003, issued April 24, 2002, SPM 089-18588-00453, issued July 15, 2004, and to demonstrate compliance with Condition D.22.7, the Permittee shall maintain records of the 1-hour average CO emissions.

(f) Pursuant to 326 IAC 6.8-8-3 and 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5), (q)(1), and (r)(2)) and to document compliance with Condition D.22.1, the Permittee shall maintain records for the FCU and ESP as specified in the Continuous Compliance Plan.

(g) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.22.6, the Permittee shall keep records as specified in Sections E.1 and E.3.

(h) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition D.22.5, the Permittee shall maintain records as specified in Section E.10.

(i) In order to demonstrate compliance with Condition D.22.3, the Permittee shall maintain records of daily fresh feed to FCU 600 and the coke burned at FCU 600 each month.

(j) In order to demonstrate compliance with Condition D.22.3, the Permittee shall maintain records of monthly emissions of SO2, NOx, and CO from FCU 600.

D.22.14 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Condition D.22.2 the Permittee shall submit a report containing the average daily sulfur dioxide emission rate in pounds per hour within thirty (30) days after the end of each calendar quarter.

(b) Pursuant to 326 IAC 3-5-7 and to document compliance with Condition D.22.11(b), the Permittee shall submit reports of excess opacity emissions within thirty (30) days of the end of each quarter in which excess emissions occur. Pursuant to 321 IAC 3-5-7, the reports shall include:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. The actual opacity of each averaging period for each period in excess of the opacity limit. If the exceedance occurs continuously beyond one (1) six (6) minute period, the Permittee shall report either the percent opacity for each six (6) minute period or the highest six (6) minute average opacity for the entire period.

(5) A summary itemizing the exceedances by cause.

(c) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the standard operating procedures (SOP) submitted to OAQ for the continuous opacity monitor, updates shall be submitted biennially.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.22.5(a), the Permittee shall submit reports as specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.22.5(b), the Permittee shall submit reports as specified in Section E.4.

(f) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.22.3 and D.22.9, the Permittee shall submit reports of excess CO, SO2, and NOx emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

(g) Pursuant to 40 CFR 63, Subpart UUU and to demonstrate compliance with Condition D.22.5, the Permittee shall submit to IDEM, OAQ the reports as specified in Section E.10.

(h) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.22.6, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(i) In order to demonstrate compliance with Condition D.22.3, the Permittee shall submit quarterly reports for the fresh feed used and coke burned at FCU 600 each month. The report submitted by the Permittee does require the certification by the “Responsible Official” as defined by 326 IAC 2-7-1(34).

(j) In order to demonstrate compliance with Condition D.22.3, the Permittee shall submit quarterly reports of monthly emissions of SO2, NOx, and CO from FCU 600. The report submitted by the Permittee does require the certification by the “Responsible Official” as defined by 326 IAC 2-7-1(34).

SECTION D.23 FACILITY OPERATION CONDITIONS - No. 1 Stanolind Power Station

Facility Description [326 IAC 2-7-5(15)]:

(w) A portion of No. 1 Stanolind Power Station (SPS) constructed in 1928 and identified as Unit ID 501. The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas, are NO_x budget units:

(1) The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Boiler Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
#5 Boiler	265	501-02	None
#6 Boiler	265	501-02	None
#7 Boiler	265	501-02	None

Note: The boilers in No. 1 Stanolind Power Station are scheduled to be shut down as part of the CXHO project.

(2) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.23.1 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable:

(a) The boilers #5, 6, and 7 shall not combust fuel oil; and

(b) The boilers #5, 6, and 7 shall be permanently shutdown prior to the completion of the CXHO project.

D.23.2.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

Until the shutdown of boilers #5, 6, and 7:

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the Permittee shall comply with the following PM10 emission limitations for the No. 1 SPS (no. 1 powerstation) boilers:

Boiler	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
Stack serving Boilers #5, #6, and #7	0.0075	5.924

D.23.2.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Until the shutdown of boilers #5, 6, and 7:

Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), the Permittee shall comply with the following filterable PM10 emission limitations for the No. 1 SPS Boilers:

Boiler	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
Stack serving Boilers #5, #6, and #7	0.016	13.244 (Total)

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.23.2.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), until shutdown of boilers,5, 6 and 7, the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.23.3 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Until the shutdown of boilers # 5, 6, and 7:

Pursuant to 326 IAC 7-4.1-3, the Permittee shall comply with the following SO_2 emission limitations for the No. 1 SPS Boilers:

Boiler	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)
#5	0.033	26.24 Total
#6	0.033	
#7	0.033	

D.23.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Until the shutdown of boilers # 5, 6, and 7:

Pursuant to SPM 089-15202-00003, issued April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the No. 1SPS Boilers.

D.23.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8]

Until the shutdown of boilers #, 5, 6, and 7:

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

D.23.6 Nitrogen Oxides Budget Trading Program [326 IAC 10-4]

Until the shutdown of boilers #5, 6, and 7:

Pursuant to 326 IAC 10-4-1(a), the Permittee shall comply with Nitrogen Oxides Budget Trading program for boilers #3 through #7 which are specified in Section E.11.

D.23.7Wastewater/Waste Streams [40 CFR 60, Subpart QQQ] [326 IAC 12]

Until the shutdown of boilers # 5, 6, and 7:

Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual wastewater drains systems.

Compliance Determination Requirements

D.23.8 Operating Requirement

Until the shutdown of boilers #5, 6, and 7:

Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the No. 1SPS Boilers.

Compliance Monitoring Requirements

D.23.9 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Until the shutdown of boilers #5, 6, and 7:

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.23.10 Record Keeping Requirements

Until the shutdown of boilers #5, 6, and 7:

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.23.3 and D.23.9, the Permittee shall maintain a daily record of the following for the No. 1SPS Boilers:

(1) operational status of each facility,

(2) fuel type,

(3) average daily sulfur content for each fuel type,

(4) average daily fuel gravity for each fuel type,

(5) total daily fuel usage for each type, and

(6) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(p) and 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.23.1(b), the Permittee shall maintain records for the Boilers #5, #6, and #7 as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.23.4(a), the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.23.5(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.23.5(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(f) Pursuant to 326 IAC 10-4 and to document compliance with Condition D.23.6, the Permittee shall keep records as specified in Section E.11.

(g) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.23.7, the Permittee shall keep records as specified in Section E.6.

D.23.11 Reporting Requirements

Until the shutdown of boilers #5, 6, and 7:

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.23.3 and D.23.9, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour for the No. 1 SPS Boilers.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.23.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.23.5(a) the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.23.5(b) the Permittee shall submit reports as specified in Sections E.1 and E.4.

(e) Pursuant to 326 IAC 10-4 and to document compliance with Condition D.23.6, the Permittee shall submit reports as specified in Section E.11.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.23.7, the Permittee shall submit reports as specified in Section E.6.

SECTION D.24 FACILITY OPERATION CONDITIONS - No. 3 Stanolind Power Station

Facility Description [326 IAC 2-7-5(15)]:

(x) A portion of No. 3 Stanolind Power Station (SPS) constructed as listed below and identified as Unit ID 503. The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas, are NO_x budget units:

(1) The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Boiler Identification	Installation Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
#1 Boiler	1948	575	503-01	(current) low-NO_x burners, an induced flue gas recirculation (IFGR) system, and an over fired air (OFA) system
#2 Boiler	1948	575	503-02	After CXHO: The low-NOx burners, IFGR and OFA will be replaced by conventional burners and a Selective Catalytic Reduction (SCR) system on Boilers # 1, 2, 3, 4, 6
#3 Boiler	1951	575	503-03	
#4 Boiler	1951	575	503-04	
#6 Boiler	1953	575	503-05	

(2) Five (5) direct-fired duct burners, permitted in 2008, rated at 41 mmBTU/hr each, equipped with low NOx burners and controlled by a Selective Catalytic Reduction (SCR) system.

(3) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.24.1.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), PM10 emissions from each stack serving No. 3 power station boilers #1, #2, #3, #4 and #6 shall not exceed 0.0075 pounds per million Btu heat input and 4.28 pounds per hour for each boiler.

D.24.1.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), filterable PM10 emissions from each stack serving Boilers #1, #2, #3, #4 and #6 shall not exceed 0.030 pounds per million Btu heat input and 17.49 pounds per hour for each boiler.

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.24.1.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.24.2 Lake County PM10 Emissions Limitations [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2, PM emissions from the five (5) duct burners shall not exceed 0.03gr/dscf.

D.24.3 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from Boilers #1, #2, #3, #4 and #6 shall each not exceed 18.98 pounds per hour and 0.033 pounds per million Btu heat input.

D.24.4 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall not combust fuel oil at boilers # 1,2,3,4 and 5 and shall comply with the following for No. 3 Stanolind Power Station:

After the installation of the duct burners and the conventional burners and a Selective Catalytic Reduction (SCR) on boilers 1,2,3,4 and 6, the Permittee shall comply with the following for boilers 1, 2, 3, 4, and 6 at the stack vent:

(a) The emissions of NOx shall not exceed 0.02 pound per million BTU.

(b) The emissions of VOC shall not exceed 0.0054 pound per million BTU.

(c) The emissions of PM shall not exceed 0.0019 pound per million BTU.

(d) The firing rate (total) shall not exceed 24,303,535 mmBTU per 12 consecutive month period, with compliance determined at the end of each month.

(e) The firing rate (total) at the five (5) duct burners shall not exceed 1,732,947 mmBTU per 12 consecutive month period, with compliance determined at the end of each month.

(f) The emissions of CO (total) from boilers 1, 2, 3, 4, and 6 and the five (5) duct burners shall not exceed 260.4 tons per 12 consecutive month period, with compliance determined at the end of each month.

(g) The emissions of PM-10 from each boiler/SCR stack shall not exceed 0.0087 pound per million BTU.

Compliance with the limits on annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.24.5 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the No. 3SPS Boilers and the five (5) duct burners.

D.24.6 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 12][40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may request the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements of Sections E.1 and E.2 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Prior to start-up of the boilers 1, 2, 3, 4 and 6 after installation of the duct burners the conventional burners and a Selective Catalytic Reduction (SCR), BP shall make a determination as to whether 40 CFR 60, Subpart GGGa has been triggered by component changes made on the boilers as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.24.7 Nitrogen Oxides Budget Trading Program [326 IAC 10-4]

Pursuant to 326 IAC 10-4-1(a), the Permittee shall comply with Nitrogen Oxides Budget Trading program for boilers #1 through #4 and #6, which are specified in Section E.11.

D.24.8 Wastewater/Waste Streams [326 IAC 12] [40 CFR 60, Subpart QQQ]

Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual wastewater drains systems.

Compliance Determination Requirements

D.24.9 Operating Requirement

(a) Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003 and SPM 089-18588-00453, issued July 15, 2004, fuel oil shall not be used as fuel for the No. 3SPS Boilers.

(b) Compliance with the limits in Condition D.24.4(a), (b), (c) and (g) shall be demonstrated as specified in Condition D.0.3.

D.24.10 Continuous Emissions Monitoring

The CO analyzer for the boiler/duct burner stacks shall be calibrated, maintained, and operated for determining compliance with CO emissions limits for the boilers 1, 2, 3, 4, and 6 and the five (5) duct burners in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements

D.24.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.24.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.24.3 and D.24.9 the Permittee shall maintain a daily record of the following for the No. 3 SPS Boilers:

(1) operational status of each facility,

(2) fuel type,

(3) average daily sulfur content for each fuel type,

(4) average daily fuel gravity for each fuel type,

(5) total daily fuel usage for each type, and

(6) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(p) and 326 IAC 6-1-10.1(n)(5)), and to document compliance with Condition D.24.1(b), the Permittee shall maintain records as specified in the Continuous Compliance Plan.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.24.6(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) In order to demonstrate compliance with Condition D.24.3, the Permittee shall maintain records of monthly firing rates and CO emissions at No. 3 Stanolind Power Station boilers 1, 2, 3, 4, 6, and the five (5) duct burners.

(e) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.24.5, the Permittee shall maintain the records specified in Section E.2.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.24.8, the Permittee shall maintain records specified in Section E.6.

D.24.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.24.3 and D.24.9, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour for the No. 3 SPS Boilers.

(b) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.24.6(a) the Permittee shall submit reports as specified in the LDAR plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.24.5, the Permittee shall submit reports as specified in Section E.2.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.24.8, the Permittee shall submit reports as specified in Section E.6.

(e) In order to demonstrate compliance with Condition D.24.4, the Permittee shall submit a quarterly summary of the monthly firing rates and CO emissions the boilers 1, 2, 3, 4, 6 and five (5) duct burners to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(f) Pursuant to 326 IAC 3-5-7 and to document compliance with Condition D.24.3, the Permittee shall submit reports of excess CO emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
    (A) Date of downtime.
    (B) Time of commencement.
    (C) Duration of each downtime.
    (D) Reasons for each downtime.
    (E) Nature of system repairs and adjustments

SECTION D.25FACILITY OPERATION CONDITIONS - Hazardous Waste Treatment Facility

Facility Description [326 IAC 2-7-5(15)]:

(y) Hazardous Waste Treatment System:

Dewatering and thermal desorption system for processing sludge, to be installed as part of CXHO project, including dissolved air flotation skimmimgs (DAF) and API oil/water separator sludge. The dewatering system will be equipped with a wet scrubber and carbon canister system and the thermal desorption unit will be equipped with a vapor recovery system to optimize absorption of hydrocarbons The feed rate capacities at the dewatering system and thermal desorption systems are 22,500 tons of feed per year and 9,000 dry tons of solids per year, per year, respectively. This facility includes the following emission sources and may include insignificant activities listed in Section A.4 of the permit:

(1) Two (2) centrifuges;

(2) Two (2) sludge surge tanks;

(3) One (1) oil/water mixture surge tank;

(4) One (1) enclosed auger transfer system;

(5) One (1) vapor recovery system on the thermal desorption unit including: an oil condensing/scrubbing system, a water condensing/scrubbing system, and an oil water separator. Uncondensed vapors from this system are routed to the two (2) diesel fired burners for destruction of VOCs.

Insignificant Activities:

(6) Two (2) diesel fired burners rated at 4 mmBTU/hr each, to supply heat to the thermal desorption system.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.25.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from each of the two (2) diesel fired burners shall not exceed 0.03 grains per dry standard cubic foot.

D.25.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for the dewatering and thermal desorption system:

The VOC emissions from the thermal desorption, thermal dewatering system and associated fugitives shall not exceed 2.4 tons per 12 consecutive month period, with compliance at the end of each month.

Compliance with the VOC emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

Compliance Determination Requirements

D.25.3 Petroleum Refineries [326 IAC 8-4-2]

Pursuant to 326 IAC 8-4-2(2), the Permittee shall equip all wastewater (oil/water) separators, forebay, and openings in covers with lids or seals such that the lids or seals are in the closed position at all times except when in actual use.

D.25.4 Wastewater / Waste Streams [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for all wastewater tanks and waste streams associated with the dewatering and thermal desorption system, individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, subpart CC specified in Section D.1.

D.25.5 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil-water separators, and closed-vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

D.25.6 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may request the Permittee to revise the plan.

(d) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements of Sections E.1 and E.2 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.25.7 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the two (2) thermal desorption burners.

Compliance Monitoring Requirements

D.25.8 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.25.9 Record Keeping Requirements

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall keep records as specified in Section E.1 and E.3.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall keep records as specified in Section E.6.

(c) Pursuant to 40 CFR 60, Subpart J, the Permittee shall keep records as specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.25.6, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

D.25.10 Reporting Requirements

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall submit reports as specified in Section E.6.

(c) Pursuant to 40 CFR 60, Subpart J, the Permittee shall submit reports as specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.25.6, the Permittee shall submit reports as specified in the LDAR plan.

SECTION D.26 FACILITY OPERATION CONDITIONS - Wastewater Treatment Plant

Facility Description [326 IAC 2-7-5(15)]

(z) Wastewater Treatment Plant (WWTP), identified as Unit ID 544. This facility treats the water used in the refining process that comes into contact with oil or chemicals. In the first step, the heavier solids are removed at the inlet to the WWTP and the floating oil is skimmed from the surface of the wastewater in the API separator boxes. The oil is then recycled back to the refinery. The water is then aerated in the Air Flotation Unit where additional solid impurities are floated and skimmed. Thereafter, it moves to the Activated Sludge Plant where special bacteria digest the remaining contaminants. The water then passes through a clarifier and then eight (8) final filters before being returned to Lake Michigan. This facility includes the following emission sources and may include insignificant activities listed in section A.4 of this permit:

(1) The following units are equipped with closed vent systems: oil sump P-1, oil sump P-2, and Diffused Air Floatation (DAF) Secondary Boxes, which vent to a biofilter and carbon canisters; Tank 569 is equipped with a conservation vent.

(2) The following units are equipped with a fixed-roof or floating roof: Interceptor Box, Diversion Box (from Tank 5051 to DAF), DAF Flash Mixer, DAF Influent Channel, DAF Effluent Channel, DAF Primary Boxes, and DAF Sump.

(3) One (1) storage tank (identified as Tank 5051) having a maximum storage capacity of 10,000,000 gallons, constructed in 1988 and equipped with an external floating roof.

(4) One (1) storage tank (identified as Tank 5050) having a maximum storage capacity of 10,000,000 gallons, constructed in 1988. This tank is used for storm event and upset impoundments.

(5) Seven (7) oil-water/solids separator units enclosed with a fixed-roof: Bar Screen, #7 API Separator Fixed Cover, #7 API Separator Primary Inlet, #7 API Separator Secondary Inlet, #7 API Separator Secondary Outlet, #7 API Separator Inlet Channel Section, and #7 API Separator Gear Boxes.

(6) One (1) storage tank (identified as Tank 5052) having a maximum storage capacity of 11,676,000 gallons, constructed as part of the CXHO Project. This tank is used as a stormwater equalization tank and is equipped with an external floating roof.

(7) A brine treatment system with seven (7) wastewater tanks with vertical fixed roofs, constructed as part of CXHO project, identified as:

(A) TK-105A, with a storage capacity of 867,180 gallons;
(B) TK-105B, with a storage capacity of 867,180 gallons;
(C) TK-101, with a storage capacity of 66,096 gallons;
(D) TK-102, with a storage capacity of 66,096 gallons;
(E) TK-103, with a storage capacity of 66,096 gallons;
(F) TK-104A, with a storage capacity of 89,943 gallons; and
(G) TK-104B, with a storage capacity of 89,943 gallons.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.26.1 Petroleum Refineries [326 IAC 8-4-2]

Pursuant to 326 IAC 8-4-2 (2), the Permittee shall equip all wastewater (oil/water) separators, forebay, and openings in covers with lids or seals such that the lids or seals are in the closed position at all times except when in actual use.

D.26.2 Wastewater / Waste Streams [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for tank 5051, individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, subpart CC specified in Section D.1.

(d) Pursuant to 40 CFR 63.647 of 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements of 40 CFR 61, Subpart FF, specified in Section E.3, for stormwater equalization tank 5052.

(e) Pursuant to 40 CFR 63.647 of 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements of 40 CFR 61, Subpart FF, specified in Section E.3, for the seven (7) storage tanks in the brine treatment facility.

D.26.3 Volatile Organic Compound (VOC) Emission Offset

Pursuant to OP 45-08-93-0574, issued January 12, 1990, the VOC emissions from the Oil-Water Separator (#7) shall not exceed 602 tons per year.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.26.4 Record Keeping Requirements

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.26.2(a), the Permittee shall keep records as specified in Section E.1 and E.3.

(b) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.26.2(b), the Permittee shall keep records as specified in Section E.6.

D.26.5 Reporting Requirements

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.26.2(a), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(b) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.26.2(b), the Permittee shall keep records as specified in Section E.6.

SECTION D.27 FACILITY OPERATION CONDITIONS - Oil Movements

Facility Description [326 IAC 2-7-5(15)]

(aa) Oil Movements, identified as Unit 640. This facility is used to store, blend, and ship products. Gasoline blending components are custom blended into various grades of gasoline. Additive and other compounds are blended into the products to give them their unique characteristics. Furnace oil and other distillates are also blended using components from process units or storage. Crude oil and feedstocks for process units and products are also stored at this location. Product loading operations include the pipeline and railcar racks. This facility includes the following emission sources and may include insignificant activities listed in section A.4 of this permit:

(1) One (1) internal floating roof storage tank identified as 3730, storing ethanol, constructed in 1955, with a maximum storage capacity of 1,050,721 gallons.

(2) Ten (10) external floating roof storage tanks storing petroleum hydrocarbon with vapor pressure less than 15 psia, comprising the following tanks:

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3529	1948	858,000
3637	1956 permitted in 2008 for reconstruction (SPM 089-25488-00453)	6,353,000
3901	1956	1,906,000
3902	1956	1,906,000
3915	1980	6,353,460
3916	1980	13,666,998
3917	1980	25,413,839
3918	1980	13,666,998
3919	1980	13,666,998
3920	1980	13,666,998

(3) Sixty-seven (67) internal floating roof storage tanks, storing petroleum hydrocarbon with vapor pressure less than 15 psia, comprising the following tanks:

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3474	1992	3,734,422
3475	1994	3,865,445
3476	1984	3,085,016
3477	1971	4,066,214
3480	1982	4,026,505
3482	1972	169,426
3483	1924	3,382,264
3484	1996	3,865,445
3486	1979	4,026,505
3487	1980	4,026,505
3488	1994	3,865,445
3489	1996	3,865,445
3492	1925/1971	3,382,000
3493	1995	3,865,445
3510	1949	4,235,640
3511	1973	4,066,214
3512	1958	4,066,214
3513	1971	4,066,214
3514	1984	4,066,214
3525	1981	4,026,505

3526	1943/1979	4,026,505
3527	1991	3,382,264
3528	1993	3,865,445
3531	1948/1997	857,717
3532	1953	868,306
3533	1953	4,235,640
3534	1955/1973	71,000
3549	1993	588,283
3553	1981	5,070,343
3554	1981	5,070,343
3558	1972/1986	376,501
3600	1993	847,128
3601	1977	3,702,020
3602	1979	3,856,271
3604	1980	3,856,271
3605	1977	3,702,000
3622	1993	3,865,445
3624	1932	3,382,264
3629	1992	3,865,445
3631	1944	3,382,000
3633	1950	5,282,000
3635	1954	5,070,000
3639	1956	6,353,460
3641	1956	6,353,460
3701	1943/1993	3,382,264
3702	1943/1982/1997	3,382,264
3703	1944/1982 (replaced in 2006)	3,382,264
3704	1944/1980	3,382,264
3705	1944	3,382,264
3706	1944	3,382,264
3707	1944	3,382,264
3708	1943	853,895
3709	1943	825,434
3710	1943	2,059,000
3715	1945/1987/1998	3,382,264
3716	1996	3,865,445
3727	1948	857,717
3728	1970	857,717
3860	1993	211,782
3900	1956/2005	1,906,000
3904	1956/1986	3,388,512
3905	1956	6,353,460
3907	1956/1996	3,388,512
3909	1956	3,388,512
3911	1956/1986	3,388,512
3912	1956	6,353,460
3914	1956	3,388,512

(4) Miscellaneous Storage tanks including the following:

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity	Vapor Pressure of Liquid (psia)
D-424	4ULTRAFORMER	Methanol Tank	--	3,744	<0.5
F-011	4B TREATER	Casper Dewaterer	1949	17,624	<0.5

TK-0563	INCINERATOR	Aux. Fuel Oil	1971	49,378	<0.5
TK-3228	CRUDE STA	Decanted Oil	1948	596,570	<0.5
TK-3234	CRUDE STA	Decanted Oil	1940	858,298	<0.5
TK-3464	BERRY LAKE	Decanted Oil	1957	2,705,472	<0.5
TK-3465	BERRY LAKE	Plant Fuel	1973	3,413,088	<0.5
TK-3468	BERRY LAKE	TGO	1958	3,381,840	<0.5
TK-3491	SO. TK FLD.	Lsho	1992	3,876,768	<0.5
TK-3496	SO. TK FLD.	Distillate	1992	3,876,768	<0.5
TK-3498	SO. TK FLD.	Amoco Premier Diesel [Future Lsfo]	1929	3,373,413	<0.5
TK-3499	SO. TK FLD.	Amoco Premier Diesel [Future Lsfo]	1996	3,870,720	<0.5
TK-3500	SO. TK FLD.	Furnace Oil [Future Hmd]	1996	3,870,720	<0.5
TK-3505	SO. ANNEX	Heater Oil	1949	4,254,768	<0.5
TK-3509	SO. TK FLD.	Furnace Oil	1948	3,381,840	<0.5
TK-3546	SO. TK FLD.	Bronze Dye	1962	16,800	<0.5
TK-3547	SO. TK FLD.	Purple Dye	1962	16,800	<0.5
TK-3548	SO. TK FLD.	Isonox 133	1962	16,800	<0.5
TK3567	--	--	--	17,000	<0.5
TK-3569	MARINE DOCK	DCO	1981	4,796,064	<0.5
TK-3571	MARINE DOCK	HS Resid/Black Oil	1971	5,539,968	>0.5 and <0.75
TK-3572	MARINE DOCK	HS Resid/Black Oil	1971	5,539,968	>0.5 and <0.75
TK-3606	STIGLITZ PK.	Amoco Jet Fuel A [New 1996]	1996	3,701,376	<0.5
TK-3607	STIGLITZ PK.	Amoco Jet Fuel A	1993	3,729,600	<0.5
TK-3609	STIGLITZ PK.	HS Resid	1973	9,652,608	<0.5
TK-3610	STIGLITZ PK.	HS Resid	1973	9,652,608	<0.5
TK-3611	STIGLITZ PK.	HS Resid	1973	8,513,400	<0.5
TK-3613	STIGLITZ PK.	HS Resid	1992	3,876,768	<0.5
TK-3711	IND. TK FLD.	Lcco	1993	2,818,368	<0.5
TK-3712	IND. TK FLD.	Lcco	1945	3,357,600	<0.5
TK-3714	IND. TK FLD.	Distillate/Gas Oil	1999	3,852,576	<0.5
TK-3717	IND. TK FLD.	Fcu Feed Mixed	1943	3,263,190	<0.5
TK-3718	IND. TK FLD.	Gas Oil	1996	3,871,379	<0.5
TK-3719	IND. TK FLD.	Gas Oil	1943	3,357,600	<0.5
TK-3720	IND. TK FLD.	Gas Oil	1946	3,357,600	<0.5
TK-3721	IND. TK FLD.	Gas Oil	1946	3,357,600	<0.5
TK-3722	IND. TK FLD.	Gas Oil	1952	4,227,300	<0.5
TK-3723	IND. TK FLD.	Gas Oil	1954	3,386,880	<0.5
TK-3726	IND. TK FLD.	Amoco Jet Fuel A	1948	857,356	<0.5
TK-3733	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,383,520	<0.5
TK-3734	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,383,520	>0.5 and <0.75
TK-3735	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,411,072	<0.5
TK-3867	SO. TK FLD.	Stadis 450	1967	17,640	<0.5
TK-3868	SO. TK FLD.	Amogard	1953	17,640	>0.5 and <0.75
TK-3869	SO. TK FLD.	Pour Depressant	1956	23,436	<0.5
TK-3872	CRUDE STA	Used Motor Oil	1985	15,120	<0.5
TK-3876	South TF	Cetane Improver	1993	14,381	<0.5
TK-3906	J&L TK FLD.	Lsfo	1956	3,381,840	>0.5 and <0.75
TK-3908	J&L TK FLD.	Amoco Premier Diesel	1956	3,381,840	<0.5
TK-3910	J&L TK FLD.	Furnace Oil [Hs]	1956	3,381,840	<0.5
TK-3913	J&L TK FLD.	Furnace Oil [Ls]	1956	3,402,977	<0.5
TK-6078	ASPHALT	HS Resid/Black Oil	1948	1,931,000	<0.5
TK-6113	ASPHALT	Paving Base	1944	810,600	<0.5
TK-6114	ASPHALT	Paving Base	1944	810,600	<0.5

TK-6125		Paving Base	1998	3108932	<0.5
TK-6126		Paving Base	1999	3,108,000	<0.5
TK-6127		Paving Base	2000	3,108,000	<0.5
TK-6128		Paving Base	1971	3,225,600	<0.5
TK-6129		Paving Base	2005	3,108,000	<0.5
TK-6148		Paving Base	1948	3,108,000	<0.5
TK-6149		Paving Base	1948	3,108,000	<0.5
TK-6150		HS Resid	1986	810,600	<0.5
TK-6153		HS Resid	1979	1,386,000	<0.5
TK-6248	ASPHALT	Low Sul Resid	1973	7,218,928	<0.5
TK-6249	ASPHALT	Low Sul Resid	1973	7,218,928	<0.5
TK-6250	ASPHALT	HS Resid	1971	7,218,928	<0.5
TK-6251	ASPHALT	Paving Base	1971	7,218,928	<0.5
TK-6252	ASPHALT	HS Resid	1972	7,215,268	<0.5
TK-6253	ASPHALT	Paving Base	1971	7,218,928	<0.5
TK-6261	ASPHALT	HS Resid	1973	451,183	<0.5
TK-6262	ASPHALT	HS Resid	1972	451,183	<0.5
TK-0559	ASU	Out of Service	1989	146,869	--
TK-0560	ASU	Out of Service	1948	587,477	--
TK-0568		Out of Service	Before 1973	--	--
TK-3167		Out of Service	1926	3,361,114	--
TK-3168		Out of Service	1926	1,931,170	--
TK-3169		Out of Service	1926	3,361,114	--
TK-3232	CRUDE STA	Out of Service	1940	857,356	--
TK-3259	CRUDE STA	Out of Service	1951	846,720	--
TK-3260	CRUDE STA	Out of Service	1930	375,986	--
TK-3279	MARINE DOCK	Out of Service	1951	85,302	--
TK-3309	CRUDE STA	Out of Service	NA	7,050	--
TK-3373		Out of Service	--	--	--
TK-3471	SO. TK FLD.	Out of Service	1973	7,050	--
TK-3485	SO. TK FLD.	Out of Service	1924	3,373,413	--
TK-3494	SO. TK FLD.	Out of Service	1926	3,373,413	--
TK-3497	SO. TK FLD.	Out of Service	1926	3,373,413	--
TK-3506	SO. ANNEX	Out of Service	1936	3,373,413	--
TK-3507	SO. ANNEX	Out of Service	1936	3,373,413	--
TK-3508	SO. ANNEX	Out of Service	1936	3,366,720	--
TK-3603	STIGLITZ PK.	Out of Service	1922	3,084,480	--
TK-3608	STIGLITZ PK.	Out of Service	1954	3,849,300	--
TK-3713	IND. TK FLD.	Out of Service	1944	3,357,600	--
TK-3903	J&L TK FLD.	Out of Service	1956	3,381,840	--
TK-6222		Out of Service	--	3,000	--
TK-6223		Out of Service	--	211,400	--
TK-6224		Out of Service	--	211,400	--
W-306	MWTP	Out of Service	--	--	--

(5) One (1) oil-water separator identified as the J & L Separator.

(6) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.27.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) and Benzene [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 14][40 CFR 61, Subpart J]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Pursuant to 40 CFR 61, Subpart J, the Permittee shall comply with the requirements specified in Section E.5 for leaks of benzene from pumps, pressure relief devices, sampling connection systems, open-ended lines or valves, and valves.

(d) Pursuant to 40 CFR 63.640(p), equipment that is subject to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart J is required only to comply with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

(e) Pursuant to 40 CFR 60, Subpart GGG, the Permittee shall comply with the requirements specified in Section E.13 for equipment leaks of VOC from compressors and other process equipment that is located at the J & L Tank Field and was modified after modified January 4, 1983. Pursuant to 40 CFR 63.640(p), equipment that is subject to both 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC are required to comply only with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.27.2 Petroleum Liquid Storage Facilities [326 IAC 8-4-3]

Pursuant to 326 IAC 8-4-3(a), the Permittee shall comply with the requirements in this condition for all petroleum liquid storage vessels with capacities greater than 39,000 gallons containing volatile organic compounds whose true vapor pressure is greater than 1.52 psi. Tanks subject to this condition include: 3474, 3475, 3476, 3477, 3480, 3482, 3483, 3484, 3486, 3487, 3488, 3489, 3493, 3511, 3512, 3513, 3514, 3525, 3526, 3527, 3528, 3531, 3532, 3533, 3549, 3553, 3554, 3558, 3601, 3605, 3629, 3639, 3641, 3701, 3702, 3703, 3704, 3707, 3716, 3728, 3730, 3900, 3904, 3905, 3907, 3909, 3911, 3912, 3914, 3916, 3917, 3918, 3919, 3920, 3492, 3529, 3631, 3637, 3706, 3860, and 3901.

Pursuant to 326 IAC 8-4-3(a), the Permittee shall comply with the following requirements for all petroleum liquid storage vessels with capacities greater than 39,000 gallons containing volatile organic compounds whose true vapor pressure is greater than 1.52 psi.

(a) Pursuant to 326 IAC 8-4-3(b), the Permittee shall not permit the use of an affected fixed roof tank unless:

(1) The tank has been retrofitted with an internal floating roof equipped with a closure seal, or seals, to close the space between the roof edge and tank wall unless the source has been retrofitted with equally effective alternate control which has been approved,

(2) The facility is maintained such that there are no visible holes, tears or other opening in the seal or any seal fabric or materials,

(3) All openings, except stub drains, are equipped with covers, lids or seals such that:

(A) the cover, lid or seal is in the closed position at all times except when in actual use;

(B) automatic bleeder vents are closed at all times except when in actual use;

(C) rim vents if provided, are set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

(b) Pursuant to 326 IAC 8-4-3(c)(1), the Permittee shall not store petroleum liquid in an affected open top tank having a cover consisting of a double deck or pontoon single deck which rests upon and is supported by the petroleum liquid being contained and is equipped with a closure seal or seals to close the space between the roof edge and tank wall shall not be used to store volatile organic liquids unless:

(1) The tank has been fitted with:

(A) a continuous secondary seal extending from the floating roof to the tank wall (rim-mounted secondary seal); or

(B) a closure or other device approved by the commissioner which is equally effective.

(2) All seal closure devices meet the following requirements:

(A) there are no visible holes, tears, or other openings in the seal(s) or seal fabric;

(B) the seal(s) are intact and uniformly in place around the circumference of the floating roof between the floating roof and the tank wall;

(C) for vapor mounted primary seals, the accumulated gap area around the circumference of the secondary seal where a gap exceeding one-eighth (1/8) inch exists between the secondary seal and the tank wall shall not exceed 1.0 square in per foot of tank diameter. There shall be no gaps exceeding one-half (½) inch between the secondary seal and the tank wall of welded tanks and no gaps exceeding one (1) inch between the secondary seal and the tank wall of riveted tanks.

(3) All openings in the external floating roof, except for automatic bleeder vents, rim space vents, and leg sleeves, are:

(A) equipped with covers. seals, or lids in the closed position except when the openings are in actual use; and

(B) equipped with projections into the tank which remain below the liquid surface at all times.

(4) automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports;

(5) rim vents are set to open when the roof is being floated off the leg supports or at the manufacturer's recommended setting ; and

(6) emergency roof drains are provided with slotted membrane fabric covers or equivalent covers which cover at least ninety percent (90%) of the opening.

D.27.3 Volatile Organic Liquid Storage Vessels [326 IAC 8-9]

Pursuant to 326 IAC 8-9, the Permittee shall comply with the following requirements for storage tanks 3529, 3901, 3902, 3912, 3477, 3482, 3483, 3492, 3510, 3512, 3513, 3532, 3624, 3631, 3633, 3635, 3639, 3641, 3705, 3706, 3709, 3728, 3730, 3905, 3909, 3914, 3511, 3601, 3480, 3486, 3487, 3525, 3526, 3553, 3554, 3605, 3703, 3704, 3533, 3915, 3916, 3917, 3918, 3919, 3920, D-424, F-011, TK-3546, TK-3547, TK-3548, TK-3567, TK-3867, TK-3868, TK-3869, TK-3872, TK-3876, TK-0563, TK-3228, TK-3234, TK-3464, TK-3465, TK-3468, TK-3491, TK-3496, TK-3498, TK-3499, TK-3500, TK-3505, TK-3509, TK-3569, TK-3606, TK-3607, TK-3609, TK-3610, TK-3611, TK-3613, TK-3711, TK-3712, TK-3714, TK-3717, TK-3718, TK-3719, TK-3720, TK-3721, TK-3722, TK-3723, TK-3726, TK-3733, TK-3735, TK-3908, TK-3910, TK-3913, TK-6078, TK-6113, TK-6114, TK-6125, TK-6126, TK-6127, TK-6128, TK-6129, TK-6148, TK-6149, TK-6150, TK-6153, TK-6248, TK-6249, TK-6250, TK-6251, TK-6252, TK-6253, TK-6261, TK-6262, TK-3571, TK-3572, TK-3734, and TK-3906. For Storage tanks 3534, 3602, 3604, 3708, 3727, D-424, F-011, TK-3546, TK-3547, TK-3548, TK-3567, TK-3867, TK-3868, TK-3869, TK-3872, TK-3876, TK-0563, TK-3228, TK-3234, TK-3464, TK-3465, TK-3468, TK-3491, TK-3496, TK-3498, TK-3499, TK-3500, TK-3505, TK-3509, TK-3569, TK-3606, TK-3607, TK-3609, TK-3610, TK-3611, TK-3613, TK-3711, TK-3712, TK-3714, TK-3717, TK-3718, TK-3719, TK-3720, TK-3721, TK-3722, TK-3723, TK-3726, TK-3733, TK-3735, TK-3908, TK-3910, TK-3913, TK-6078, TK-6113, TK-6114, TK-6125, TK-6126, TK-6127, TK-6128, TK-6129, TK-6148, TK-6149, TK-6150, TK-6153, TK-6248, TK-6249, TK-6250, TK-6251, TK-6252, TK-6253, TK-6261, TK-6262, TK-3571, TK-3572, TK-3734, and TK-3906, which are used to store liquids with vapor pressures less than 0.5 psia, the Permittee shall comply only with the recordkeeping and reporting requirements specified in Condition D.27.9(e). For storage tanks 3633, 3635, 3710, 3571, TK-3572, TK-3734, and TK-3906, which are used to store liquids with vapor pressures between 0.5 and 0.75 psia, the Permittee shall comply only with the requirements specified in Condition D.27.9(e) and (i).

(a) Pursuant to 326 IAC 8-9-4(a), the Permittee shall comply with the following requirements for each vessel having a capacity greater than or equal to thirty-nine thousand (39,000) gallons, that stores VOL with a maximum true vapor pressure greater than or equal to seventy-five hundredths (0.75) pound per square inch absolute (psia) but less than eleven and one-tenth (11.1) psia:

(1) On or before May 1, 1996, for each vessel having a permanently affixed roof, the Permittee shall install one (1) of the following:

(A) An internal floating roof meeting the standards in section (b) of this Condition.

(B) An equivalent emissions control system resulting in equivalent emissions reductions to that obtained in paragraph (a)(1)(A).

(2) For each vessel having an internal floating roof, install one (1) of the following:

(A) At the time of the next scheduled cleaning, but not later than ten (10) years after May 1, 1996, an internal floating roof meeting the standards in section (b) of this Condition,

(B) On or before May 1, 1996, an equivalent emissions control system resulting in equivalent emissions reductions to that obtained in paragraph (a)(2)(A).

(3) For each vessel having an external floating roof, install one (1) of the following:

(A) At the time of the next scheduled cleaning, but not later than ten (10) years after May 1, 1996, an external floating roof meeting the standards in section (c) of this Condition.

(B) On or before May 1, 1996, an equivalent emissions control system resulting in equivalent emissions reductions to that obtained in paragraph (a)(3)(A) of this condition.

(b) Pursuant to 326 IAC 8-9-4(c), for each internal floating roof, the Permittee shall comply with the following standards:

(1) The internal floating roof shall float on the liquid surface, but not necessarily in complete contact with it, inside a vessel that has a permanently affixed roof.

(2) The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the vessel is completely emptied or subsequently emptied and refilled.

(3) When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(4) Each internal floating roof shall be equipped with one (1) of the following closure devices between the wall of the vessel and the edge of the internal floating roof:

(A) A foam or liquid-filled seal mounted in contact with the liquid (liquid-mount seal).

(B) Two (2) seals mounted one (1) above the other so that each forms a continuous closure that completely covers the space between the wall of the vessel and the edge of the internal floating roof. The lower seal may be vapor mounted, but both shall be continuous.

(C) A mechanical shoe seal that consists of a metal sheet held vertically against the wall of the vessel by springs or weighted levers and that is connected by braces to the floating roof. A flexible coated fabric, or envelope, spans the annular space between the metal sheet and the floating roof.

(5) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents shall provide a projection below the liquid surface.

(6) Each opening in a noncontact internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains shall be equipped with a cover or lid that shall be maintained in a closed position at all times (with no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(7) Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(8) Rim space vents shall be equipped with a gasket and shall be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(9) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least ninety percent (90%) of the opening.

(10) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(c) Pursuant to 326 IAC 8-9-4(e), the Permittee shall comply with the following standards applicable to each external floating roof:

(1) Each external floating roof shall be equipped with a closure device between the wall of the vessel and the roof edge. The closure device shall consist of two (2) seals, one (1) above the other. The lower seal shall be referred to as the primary seal; the upper seal shall be referred to as the secondary seal.

(2) Except as provided in 326 IAC 8-9-5(c)(4), the primary seal shall completely cover the annular space between the edge of the floating roof and vessel wall and shall be either a liquid-mounted seal or a shoe seal.

(3) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the vessel in a continuous fashion except as allowed in 326 IAC 8-9-5(c)(4).

(4) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface.

(5) Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof shall be equipped with a gasketed cover, seal or lid that shall be maintained in a closed position at all times, without visible gap, except when the device is in actual use.

(6) Automatic bleeder vents shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(7) Rim vents shall be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents shall be gasketed.

(8) Each emergency roof drain shall be provided with a slotted membrane fabric cover that covers at least ninety percent (90%) of the area of the opening.

(9) The roof shall be floating on the liquid at all times, for example, off the roof leg supports, except when the vessel is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

D.27.4 VOC and HAP Emissions From Storage Vessels [326 IAC 12] [40 CFR 60, Subpart K] [40 CFR 60, Subpart Ka] [40 CFR 60, Subpart Kb] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 40 CFR 60.110a, storage vessels 3480, 3486, 3487, 3525, 3526, 3553, 3554, 3602, 3604, 3703, 3704, 3915, 3916, 3917, 3918, 3919, and 3920 are affected facilities under 40 CFR 60, Subpart Ka. Unless otherwise specified in paragraph (d) of this condition, the Permittee shall operate these storage tanks in compliance with the requirements specified in Section E.8. For storage tanks 3602 and 3604, the Permittee shall comply only with the record keeping requirements in Section E.8.

(b) Pursuant to 40 CFR 60.110b, storage vessels 3474, 3475, 3476, 3484, 3488, 3489, 3493, 3514, 3527, 3528, 3531, 3549, 3558, 3600, 3622, 3629, 3701, 3702, 3715, 3716, 3860, 3900, 3904, 3907, TK-3637, and 3911 are affected facilities under 40 CFR 60, Subpart Kb. Unless otherwise specified in paragraph (d) of this condition, the Permittee shall operate these storage tanks in compliance with the requirements specified in Section E.9.

(c) Pursuant to 40 CFR 60.110, storage vessels 3534, 3601, and 3605 are affected facilities under 40 CFR 60, Subpart K. Unless otherwise specified in paragraph (d) of this condition, the Permittee shall operate these storage tanks in compliance with the requirements specified in Section E.7.

(d) Pursuant to 40 CFR 63, Subpart CC,

(1) The Permittee shall comply with the requirements specified in Section E.1, for the following Group I storage vessels: 3477, 3474, 3475, 3476, 3480, 3482, 3483, 3484, 3486, 3487, 3488, 3489, 3493, 3510, 3511, 3512, 3513, 3514, 3525, 3526, 3527, 3528, 3529, 3531, 3532, 3534, 3537, 3533, 3553, 3554, 3601, 3605, 3624, 3629, 3631, 3633, 3635, 3637, 3639, 3641, 3701, 3702, 3703, 3704, 3705, 3706, 3707, 3710, 3715, 3716, 3728, 3900, 3901, 3902, 3904, 3905, 3907, 3909, 3912, 3914, 3915, 3916, 3917, 3918, 3919, and 3920.

(2) Pursuant to 40 CFR 63.640(n)(5), Group 1 storage vessels that are also subject to the provisions of 40 CFR 60, Subparts K or Ka are required to only comply with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

(3) Pursuant to 40 CFR 63.640(n)(1), Group 1 and Group 2 storage vessels that are also subject to the provisions of 40 CFR Part 60, Subpart Kb, are required to comply only with the requirements of 40 CFR 60, Subpart Kb, except as provided in 40 CFR 63.640(n)(8).

D.27.5 Wastewater/Waste Streams [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [40 CFR 60 Subpart QQQ] [326 IAC 12]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements in Sections E.1 and E.3 for individual drain systems, oil-water separators, and closed vent systems and control devices.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems subject to 40 CFR, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, subpart CC specified in Section E.1.

D.27.6 Petroleum Refineries - Separators [326 IAC 8-4-2]

Pursuant to 326 IAC 8-4-2(2), the Permittee shall equip oil-water separators, forebay, and openings in covers with lids or seals such that the lids or seals are in the closed position at all times except when in actual use.

D.27.7 NESHAP for Organic Liquid Distribution [40 CFR 63, Subpart EEEE]

Pursuant to 40 CFR 63.2338(b), storage tank D-424 and any equipment at this source that meets the definition of an affected source under 40 CFR 63.2334 shall comply with the requirements of 40 CFR 63, Subpart EEEE, as specified in Section E.24.

Compliance Monitoring Requirements

D.27.8 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

D.27.9 Storage Vessel Inspections [326 IAC 8-9]

(a) Pursuant to 326 IAC 8-9-5(a), the Permittee shall meet the requirements of paragraph (b), (c), or (d) for each vessel subject to 326 IAC 8-9-4(a):

(b) On and after May 1, 1996, except as provided in 326 IAC 8-9-4(a)(2), the Permittee shall meet the following requirements for each vessel equipped with an internal floating roof:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal, if one is in service, prior to filling the vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the Permittee shall repair the items before filling the vessel.

(2) For vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal, if one is in service, through manholes and roof hatches on the fixed roof at least once every twelve (12) months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the Permittee shall repair the items or empty and remove the vessel from service within forty-five (45) days. If a failure that is detected during inspections required in this section cannot be repaired in forty-five (45) days and if the vessel cannot be emptied within forty-five (45) days, a thirty (30) day extension may be requested from the department in the inspection report required in 326 IAC 8-9-6(c)(3). Such a request for an extension shall document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with both primary and secondary seals:

(A) visually inspect the vessel as specified in paragraph (b)(4) of this Condition, at least every five (5) years; or

(B) Visually inspect the vessel as specified in paragraph (b)(2) of this Condition.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal, if one is in service, gaskets, slotted membranes, and sleeve seals each time the vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than ten percent (10%) open area, the Permittee shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the vessel with VOL.

(5) In no event shall the inspections required by this Condition occur at intervals greater than ten (10) years in the case of vessels conducting the annual visual inspection as specified in paragraphs (b)(2) and (b)(3)(B) of this Condition and at intervals no greater than five (5) years in the case of vessels specified in subdivision (b)(3)(A).

(c) On and after May 1, 1996, except as provided in 326 IAC 8-9-4(a)(3), the Permittee shall meet the following requirements for each vessel equipped with an external floating roof:

(1) Determine the gap areas and maximum gap widths between the primary seal and the wall of the vessel and between the secondary seal and the wall of the vessel according to the following frequency:

(A) Measurements of gaps between the vessel wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within sixty (60) days of the initial fill with VOL and at least once every five (5) years thereafter.

(B) Measurements of gaps between the vessel wall and the secondary seal shall be performed within sixty (60) days of the initial fill with VOL and at least once per year thereafter.

(C) If any source ceases to store VOL for a period of one (1) year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for purposes of paragraph (c)(1) of this Condition.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(A) Measure seal gaps, if any, at one (1) or more floating roof levels when the roof is floating off the roof leg supports.

(B) Measure seal gaps around the entire circumference of the vessel in each place where a one-eighth (1/8) inch diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the vessel and measure the circumferential distance of each such location.

(C) The total surface area of each gap described in paragraph (c)(2)(B) of this Condition shall be determined by using probes of various widths to measure accurately the actual distance from the vessel wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each by the nominal diameter of the vessel and compare each ratio to the respective standards in paragraph (c)(4) of this Condition.

(4) Make necessary repairs or empty the vessel within forty-five (45) days of identification of seals not meeting the requirements listed in paragraphs (A) and (B) as follows:

(A) The accumulated area of gaps between the vessel wall and the mechanical shoe or liquid-mounted primary seal shall not exceed ten (10) square inches per foot of vessel diameter, and the width of any portion of any gap shall not exceed one and five-tenths (1.5) inches. There shall be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(B) The secondary seal shall meet the following requirements:

(i) The secondary seal shall be installed above the primary seal so that it completely covers the space between the roof edge and the vessel wall except as provided in paragraph (c)(2)(C) of this Condition.

(ii) The accumulated area of gaps between the vessel wall and the secondary seal used in combination with a metallic shoe or liquid-mounted primary seal shall not exceed one (1) square inch per foot of vessel diameter, and the width of any portion of any gap shall not exceed five-tenths (0.5) inch. There shall be no gaps between the vessel wall and the secondary seal when used in combination with a vapor-mounted primary seal.

(iii) There shall be no holes, tears, or other openings in the seal or seal fabric.

(C) If a failure that is detected during inspections required in paragraph (c) of this condition cannot be repaired within forty-five (45) days and if the vessel cannot be emptied within forty-five (45) days, a thirty (30) day extension may be requested from the department in the inspection report required in section 6(d)(3) of 326 IAC 8-9. Such extension request shall include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed. If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal fabric, the Permittee shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the vessel with VOL.

(d) For each vessel that is equipped with a closed vent system and control device described in 326 IAC 8-9-4(a)(1)(B), (a)(2)(B), or (a)(3)(B) and meeting the requirements of 326 IAC 8-9-4(d), other than a flare, the Permittee shall operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the department in accordance with 326 IAC 8-9-5(d)(1).

(e) For each vessel that is equipped with a closed vent system and a flare to meet the requirements in 326 IAC 8-9-4(a)(4) or (d), the Permittee shall meet the requirements specified in the general control device requirements in 40 CFR 60.18(e) and 40 CFR 60.18(f)

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.27.10Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 61, Subpart J, the Permittee shall keep records as specified in Section E.5.

(d) Pursuant to 326 IAC 8-4-3(d), the Permittee shall maintain the following records for storage vessels subject to 326 IAC 8-4-3:

(1) type of petroleum liquid stored,

(2) maximum true vapor pressure to the liquid as stored, and

(3) results of inspections performed on storage vessels.

(e) Pursuant to 326 IAC 8-9-6(b), the Permittee shall maintain, for the life of the vessel, a record of the following for each vessel to which 326 IAC 8-9 applies:

(1) The vessel identification number,

(2) The vessel dimensions,

(3) The vessel capacity, and

(4) A description of the emission control equipment for each vessel described in section 4(a) or 4(b) of 326 IAC 8-9, or a schedule for installation of emission control equipment on vessels described in section 4(a) or 4(b) of 326 IAC 8-9 with a certification that the emission control equipment meets the applicable standards.

(f) Pursuant to 326 IAC 8-9-6(c) the Permittee shall maintain the following records for each vessel equipped with a permanently affixed roof and internal floating roof:

(1) A record of each inspection performed as required by section 5(b)(1) through 5(b)(4) of 326 IAC 8-9. Each record shall identify the following:

(A) The vessel inspected by identification number.

(B) The date the vessel was inspected.

(C) The observed condition of each component of the control equipment, including the following:

(i) Seals

(ii) Internal floating roof.

(iii) Fittings

(2) If any of the conditions described in 326 IAC 8-9-5(b)(2) are detected during the required annual visual inspection, a record that includes the following shall be maintained:

(A) The vessel by identification number.

(B) The nature of the defects.

(C) The date the vessel was emptied or the nature of and date the repair was made.

(3) After each inspection required by 326 IAC 8-9-5(b)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in 326 IAC 8-9-5(b)(3)(B) a record that includes the following shall be maintained:

(A) The vessel by identification number.

(B) The reason the vessel did not meet the specifications of 326 IAC 8-9-4(a)(1)(A), 8-9-4(a)(2)(A), or 8-9-5(b) and list each repair made.

(g) Pursuant to 326 IAC 8-9-6(d), the Permittee shall comply with the following record keeping requirements for each vessel equipped with an external floating roof:

(1) Keep a record of each gap measurement performed as required by section 5(c) of 326 IAC 8-9. Each record shall identify the vessel in which the measurement was made and shall contain the following:

(A) The date of measurement.

(B) The raw data obtained in the measurement.

(C) The calculations described in section 5(c)(2) and 5(c)(3) of 326 IAC 8-9.

(2) For each seal gap measurement that detects gaps exceeding the limitations specified in section 5(c) of 326 IAC 8-9, the Permittee shall maintain a record of the following:

(A) The date of measurement.

(B) The raw data obtained in the measurement.

(C) The calculations described in section 5(c)(2) and 5(c)(3) of 326 IAC 8-9.

(D) The date the vessel was emptied or the repairs made and date of repair.

(h) Pursuant to 326 IAC 8-9-6(e), the Permittee shall comply with the following record keeping requirements for any vessel with a closed vent system with a control device:

(1) The Permittee shall maintain records of the following for any vessel equipped with a control device other than a flare:

(A) The operating plan.

(B) Measured values of the parameters monitored according to section 5(d)(2) of 326 IAC 8-9.

(2) The Permittee shall meet the following requirements for any vessel equipped with a closed vent system and a flare:

(A) Keep records of all periods of operation during which the flare pilot flame is absent.

(B) Keep records of measurements required by 40 CFR 60.18(f)(1) through 40 CFR 60.18(f)(5) as required by 40 CFR 60.8.

(i) Pursuant to 326 IAC 8-9-6(g) and (h), the Permittee shall maintain the following records for storage tanks 3633, 3635, 3710, 3571, TK-3572, TK-3734, and TK-3906, which have a design capacity greater than or equal to thirty-nine thousand (39,000) gallons and store a VOL with a maximum true vapor pressure greater than or equal to 0.5 but less than 0.75 pound per square inch absolute (psia):

(1) The type of VOL stored.

(2) The dates of the VOL stored.

(3) For each day of VOL storage, the average stored temperature for VOLs stored above or below the ambient temperature or average ambient temperature for VOLs stored at ambient temperature, and the corresponding maximum true vapor pressure.

(4) The Permittee shall maintain a record and notify the department within thirty (30) days when the maximum true vapor of the liquid exceeds 0.75 psia.

(j) Pursuant to 40 CFR 60, Subpart Ka, the Permittee shall maintain records as specified in Section E.8.

(k) Pursuant to 40 CFR 60, Subpart Kb, the Permittee shall maintain records as specified in Section E.9.

(l) Pursuant to 40 CFR 60, Subpart K, the Permittee shall maintain records as specified in Section E.7.

(m) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall maintain records as specified in Section E.1.

(n) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall keep records as specified in Sections E.1 and E.3.

(o) Pursuant to 40 CFR 60, Subpart QQQ the Permittee shall keep records as specified in Section E.6.

(p) Pursuant to 40 CFR 60, Subpart GGG, the Permittee shall keep records as specified in Section E.13.

(q) Pursuant to 40 CFR 63, Subpart EEEE, the Permittee shall keep records as specified in Section E.24.

D.27.11 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.27.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.27.1(b), the Permittee shall submit reports as specified in Section E.1 and E.4.

(c) Pursuant to 40 CFR 61, Subpart J, and to document compliance with Condition D.27.1(c), the Permittee shall submit reports as specified in Section E.5.

(d) Pursuant to 326 IAC 8-9-6(c) and to document compliance with Condition D.27.2(a):

(1) If any of the conditions described in 326 IAC 8-9-5(b)(2) are detected during the required annual visual inspection, the Permittee shall furnish a report to the department within (30) days of the inspection. Each report shall identify the following:

(A) The vessel by identification number.

(B) The nature of the defects.

(C) The date the vessel was emptied or the nature of and date the repair was made.

(2) After each inspection required by 326 IAC 8-9-5(b)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in 326 IAC 8-9-5(b)(3)(B), the Permittee shall furnish a report to the department within thirty (30) days of the inspection. The report shall identify the following:

(A) The vessel by identification number.

(B) The reason the vessel did not meet the specifications of section 4(a)(1)(A), 4(a)(2)(A), or 5(b) of 326 IAC 8-9 and list each repair made.

(e) Pursuant to 326 IAC 8-9-6(d) and to document compliance with Condition D.27.9(c)

(1) Within sixty (60) days of performing the seal gap measurements required by section 5(c)(1) of 326 IAC 8-9, the Permittee shall furnish the department with a report that contains the following:

(A) The date of measurement.

(B) The raw data obtained in the measurement.

(C) The calculations described in section 5(c)(2) and 5(c)(3) of 326 IAC 8-9.

(2) After each seal gap measurement that detects gaps exceeding the limitations specified in section 5(c) of 326 IAC 8-9, the Permittee shall submit a report to the department within thirty (30) days of the inspection. The report shall identify the vessel and contain the following information:

(A) The date of measurement.

(B) The raw data obtained in the measurement.

(C) The calculations described in section 5(c)(2) and 5(c)(3) of 326 IAC 8-9.

(D) The date the vessel was emptied or the repairs made and date of repair.

(f) Pursuant to 326 IAC 8-9-6(e) and to document compliance with Condition D.27.3(a), the Permittee shall meet the following requirements for any vessel equipped with a closed vent system and a flare:

(1) Furnish the department with a report containing the measurements required by 40 CFR 60.18(f)(1) through 40 CFR 60.18(f)(5) as required by 40 CFR 60.8. This report shall be submitted within six (6) months of the initial start-up date.

(2) Furnish the department with a semiannual report of all periods recorded under 40 CFR 60.115 in which the pilot flame was absent.

(g) Pursuant to 326 IAC 8-9-5(b)(5) and 326 IAC 8-9-5(c)(6)(B), the Permittee shall notify the department in writing at least thirty (30) days prior to the filling or refilling of each vessel for which an inspection is required by 326 IAC 8-9-5(b)(1) to afford the department the opportunity to have an observer present. If the inspection required by 326 IAC 8-9-5(b)(4) or (c)(6) is not planned and the Permittee could not have known about the inspection thirty (30) days in advance of refilling the vessel, the Permittee shall notify the department at least seven (7) days prior to the refilling of the vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification, including the written documentation, may be made in writing and sent by express mail so that it is received by the department at least seven (7) days prior to the refilling.

(h) The Permittee shall notify the department in writing at least thirty (30) days prior to the filling or refilling of each vessel to afford the department the opportunity to inspect the vessel prior to the filling. If the inspection required by this subdivision is not planned and the Permittee could not have known about the inspection thirty (30) days in advance of refilling the vessel, the Permittee shall notify the department at least seven (7) days prior to the refilling of the vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the department at least seven (7) days prior to the refilling.

(i) Pursuant to 326 IAC 8-9-5(c)(5), the Permittee shall notify the department thirty (30) days in advance of any gap measurements required by 326 IAC 8-9-5(c)(1) to afford the department the opportunity to have an observer present.

(j) Pursuant to 40 CFR 60, Subpart Ka and to document compliance with Condition D.27.4(a), the Permittee shall submit reports as specified in Section E.8.

(k) Pursuant to 40 CFR 60, Subpart Kb and to document compliance with Condition D.27.4(b), the Permittee shall submit reports as specified in Section E.9.

(l) Pursuant to 40 CFR 60, Subpart K and to document compliance with Condition D.27.4(c), the Permittee shall submit reports as specified in Section E.7.

(m) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.27.4(d), the Permittee shall submit reports as specified in Section E.1.

(n) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.27.5(a), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(o) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.27.5(b), the Permittee shall submit reports as specified in Section E.6.

(p) To document compliance with Condition D.27.4(d)(2), the Permittee shall submit the following reports:

Pursuant to 40 CFR 63.654(g)(6), the Permittee shall submit Notification of Compliance Status reports no later than 60 days after the end of the 6-month period after an existing Group 1 storage tank was brought into compliance. The Notification of Compliance Status Report may be combined with the periodic report. The notifications shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
and
United States Environmental Protection Agency, Region V
Director, Air and Radiation Division
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

The notifications require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(q) Pursuant to 40 CFR 60, Subpart GGG and to document compliance with Condition D.27.2(e), the Permittee shall submit reports as specified in Section E.13.

(r) Pursuant to 40 CFR 63, Subpart EEEE, the Permittee shall submit reports as specified in Section E.24.

SECTION D.28 FACILITY OPERATION CONDITIONS - Remediation System

Facility Description [326 IAC 2-7-5(15)]:

(bb) The general facility remediation system, identified as Unit 999. Remediation includes multiple well point systems. The well point system extracts groundwater which may have a small hydrocarbon fraction. Depending on the VOC concentration, emissions generated by these systems may be routed to the atmosphere or to a thermal oxidizer. Additionally, one or more systems may route to the same oxidizer. Each system uses a common horizontal vacuum header to collect groundwater through a series of wells, and any entrained air is discharged through a vent at the vacuum pump. Recovered groundwater is then transferred to either a vapor/liquid separation tank or directly to another unit for further processing/treatment. Remediation includes the following emission sources and may also include insignificant activities listed in section A.4 of this permit.

(1) The following well point systems:

Facility I.D.	Installation Date	S/V I.D.	Normal Venting	Controls
J-136	1993	999-01	Vented Separately	Uncontrolled
J-137	1992	999-02	Vented Separately	Uncontrolled
J-138	1991 Extension 1994	999-03	J-138, J-139 and J-140 are vented with D-138 (Vapor/Liquid separation tank)	0.685 MMBtu per hour Thermal Oxidizer ITF
J-139	1981	999-04		
J-140	1981	999-05		
J-141	1988 Extension 1993	999-06	Vented Separately	Uncontrolled
J-156	1968-1970	999-07	Vented Separately	Uncontrolled
J-157	1968-1970	999-08	Vented Separately	Uncontrolled
J-158	1968-1970	999-10	J-158, & J-159 vents are common	Electric Catalytic Oxidizer 600°F min. temp., @ 1,000 scfm
J-159	1968-1970	999-11		
J-160	1968-1970 Extension 1994	999-12	Vented Separately	Electric Catalytic Oxidizer, 600°F min. temp., @ 1,000 acfm
J-161	1992	999-13	Vented Separately	0.685 MMBtu per hour Thermal Oxidizer BLTF
J-162	1996	999-14	Vented Separately	Uncontrolled
J-163	1996	999-15	Vented Separately	Uncontrolled

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.28.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2(a) (formerly 326 IAC 6-1-2(a)) (Particulate Matter Limitations for Lake County), particulate matter (PM) emissions from the BLTF and ITF thermal oxidizers shall not exceed 0.03 gr/dscf.

D.28.2 New Source Performance Standards [326 IAC 12] [40 CFR 60, Subpart J]

(a) Pursuant to 40 CFR 60, Subpart J, the Permittee shall comply with the requirements specified in Section E.2 for the BLTF and ITF thermal oxidizers, except as outlined in the

Alternative Monitoring Plan (AMP) incorporated in paragraphs (b) through (e) of this condition.

(b) To demonstrate compliance with paragraph (a) of this condition and as approved by the U.S. EPA on January 9, 2006 and September 7, 2006, the Permittee shall comply with the following alternative compliance requirements for the BLTF and ITF thermal oxidizers:

(1) Upon startup of the ITF Thermal Oxidizer, the Permittee shall conduct initial sampling. The sampling shall consist of monitoring the H_2S content of the combined fuel gas stream prior to the thermal oxidizer once per day for fourteen (14) days. The results of the initial sampling shall be submitted to the U.S. EPA and IDEM, OAQ within fourteen (14) days of completion. The terms and conditions of this AMP may be revised based on the initial sampling data.

(2) The Permittee shall conduct random detector tube sampling at each AMP monitoring location twice per week for a period of six (6) months for a total of fifty-two (52) samples. If the calculated range and variability of the data set is less than 81 ppm H_2S, the Permittee shall comply with the requirements in paragraph (b)(3) of this condition. The Permittee shall submit all test data, including raw measurements and calculated average and variability to the U.S. EPA and IDEM, OAQ within thirty (30) days of the end of each calendar quarter.

(3) The Permittee shall conduct random detector tube sampling at each AMP monitoring location monthly for a period of two calendar quarters. Sampling shall occur randomly each month with a minimum of two (2) weeks between samples. If the calculated range and variability of the data set is less than 81 ppm H_2S, then the Permittee shall comply with the requirements in paragraph (b)(4). The Permittee shall submit all test data, including raw measurements and calculated average and variability, to the U.S. EPA and IDEM, OAQ within thirty (30) days of the end of each calendar quarter.

(4) The Permittee shall continue to conduct testing on a monthly basis at each AMP monitoring location. Testing is to occur randomly once every month with a minimum of two (2) weeks between samples. If any one sample is equal to or greater than 81 ppm H_2S, then the Permittee shall comply with the requirements specified in paragraph (b)(5) of this condition for the affected thermal oxidizer. The Permittee shall submit all test data, including raw measurements, in the periodic report to the U.S. EPA and IDEM, OAQ within thirty (30) days of the end of each semi-annual period.

(5) If, at any time, a single detector tube sample value is equal to or greater than 81 ppm H_2S, the Permittee shall conduct detector tube sampling at the AMP monitoring location on a daily basis for seven (7) days. If the average detector tube result plus three (3) standard deviations for the seven (7) samples is less than 81 ppm H_2S, the Permittee shall submit the date and value of the monitoring event that triggered the additional sampling and the seven (7) day H_2S sample results in a written report submitted within thirty (30) days of the conclusion of the seven (7) day sampling. If the average plus three (3) standard deviations for the seven (7) samples is equal to or greater than 81 ppm H_2S, the Permittee shall comply with the requirements in paragraph (b)(6) of this condition. If the average plus three (3) standard deviations is less than 81 ppm H_2S, the Permittee shall resume the monitoring and reporting in accordance with the monitoring or reporting schedule listed in paragraphs (b)(1) through (4) that resulted in a sample greater than 81 ppm H_2S.

(6) If any sample detector tube data set indicates a potential for the emission limit to be exceeded, as outlined in paragraphs (e) or (b)(5) of this condition, the Permittee shall notify the U.S. EPA and IDEM, OAQ of those results before the end of the next business day following the last day of sample collection. The affected fuel gas stream shall subsequently be tested daily for a two (2) week period. After the two (2) week period is complete, sampling will continue once per week, or until the U.S. EPA approves a revised sampling schedule or makes a determination to withdraw approval of the gas stream/system from the AMP.

(c) The H_2S testing required by paragraph (b) of this condition shall be conducted using detector tubes – length of stain tube-type measurement. The detector tubes used for routine testing shall have a dual range of 1-20 and 10-200 ppm. Detector tubes with a range of 0-500 ppm shall be used for testing if the measured concentration exceeds 100 ppm H_2S.

(d) The monitoring location for the ITF and BLTF Thermal Oxidizers shall be on the fuel gas stream just prior to the thermal oxidizer. Specifically, for the ITF Thermal Oxidizer, the AMP monitoring location shall be after the vapors/gases from the well points J-138, J-139, and J-140 and the vapors from Tank D-138 combine. There shall not be vapors/gases added to the fuel stream after the AMP monitoring location.

(e) Data Range and Variability Calculation and Acceptance Criteria for the AMP: For paragraphs (b)(1) through (6) of this condition, sample range and variability shall be determined by calculating the average plus three (3) standard deviations for that test data set. If the average plus three (3) standard deviations for the test data set is less than 81 ppm H_2S, the sample range and variability are acceptable and the Permittee shall proceed to the next step of the monitoring schedule listed in paragraph (b) of this condition. If the data shows an unacceptable range and variability, the Permittee shall comply with the requirements in paragraph (b)(6) of this condition. If at any time, one detector tube sample is equal to or greater 81 ppm H_2S, the Permittee shall comply with the requirements in paragraph (b)(5).

D.28.3 VOC Emissions [326 IAC 8-7]

(a) The IDEM, OAQ has information that indicates that the remediation units are subject to the requirements of 326 IAC 8-7 (Specific VOC Reduction Requirements for Lake, Porter, Clark, and Floyd Counties). Therefore, the permit shield provided by Condition B.13 of this permit does not apply to these units with regards to 326 IAC 8-7. Pursuant to 326 IAC 8-7-3, the Permittee shall comply with one of the following three (3) compliance options for remediation system units existing as of May 31, 1995:

(1) Submit documentation demonstrating the Permittee has achieved an overall VOC reduction from baseline actual emissions of at least 98% by installation of an add-on control system in accordance with 326 IAC 8-7-3(1);

(2) If the Permittee can demonstrate that no 98% efficient VOC control technology exists that is both reasonably available and technically and economically feasible, the Permittee shall submit documentation demonstrating that the affected facility will achieve an overall VOC reduction of at least 81% from baseline actual emissions with the installation of an add-on control system in accordance with 326 IAC 8-7-3(2); or

(3) Submit documentation that the Permittee has achieved an alternative overall emission reduction with the application of reasonably available control technology that has been determined to be a reasonably available control technology by the U.S. EPA and IDEM, OAQ in accordance with 326 IAC 8-7-3(3).

The compliance information shall be submitted within one hundred and eighty (180) days of the effective date of this permit.

(b) IDEM, OAQ will reopen this permit using the provisions of 326 IAC 2-7-9 (Permit Reopening) to include detailed requirements necessary to comply with 326 IAC 8-7 and a schedule for achieving compliance with such requirements.

D.28.4 National Emissions Standards for Hazardous Air Pollutants for Site Remediation [40 CFR Part 63, Subpart GGGGG]

Pursuant to 40 CFR 63, Subpart GGGGG, the Permittee shall comply with the requirements of Section E.21 for the site remediation activities, including process vents, remediation management units, and other affected equipment.

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.28.5 Record Keeping Requirements

To document compliance with Condition D.28.2, the Permittee shall maintain records as specified in Section E.2.

D.28.6 Reporting Requirements

To document compliance with Condition D.28.2, the Permittee shall submit reports as specified in Section E.2.

SECTION D.29 FACILITY OPERATION CONDITIONS - Mechanical Shop

Facility Description [326 IAC 2-7-5(15)]:

(cc) The Mechanical Shop, identified as Unit 693. The Mechanical Shop includes the following emission sources and may also include insignificant activities listed in section A.4 of this permit:

(1) Two (2) Heat Treat Furnaces that are considered insignificant sources.

(2) Leaks from facility fuel gas lines.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.29.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, valves, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

Compliance Monitoring Requirements

D.29.2 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.29.3 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.29.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.29.1(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

D.29.4 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.29.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.29.1(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.

SECTION D.30 FACILITY OPERATION CONDITIONS - Bulk Truck Loading Facility

Facility Description [326 IAC 2-7-5(15)]:

(dd) One bulk truck loading facility, identified as the Marketing Terminal, and consisting of one (1) truck loading rack, constructed in 1972 and modified in 1992, comprised of 7 bays used for loading gasoline products and fuel oil. Four bays are dedicated to loading distillates, while the other three bays are dedicated to loading gasoline products. The maximum throughput for the truck loading facility is 1,103,760,000 gallons per year. Emissions of volatile organic compounds are controlled using a vapor combustion unit (identified as VCU).

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.30.1 National Emission Standards for HAPs from Petroleum Refineries and Standards of Performance for Bulk Gasoline Terminals [40 CFR 63, Subpart CC] [326 IAC 20-16] [40 CFR 60, Subpart XX] [326 IAC 12-1]

Pursuant to 40 CFR 60.500 and CFR 63.640(c)(5), the loading rack is an affected facility under 40 CFR 60, Subpart XX and 40 CFR 63, Subpart CC. Pursuant to 40 CFR 63.640(r), the loading rack is required to comply only with the requirements of 40 CFR 63, Subpart CC, which are specified in Sections E.1, E.15, and E.16.

D.30.2 Bulk Gasoline Terminals [326 IAC 8-4-4]

Pursuant to 326 IAC 8-4-4(Bulk Gasoline Terminals), the source shall comply with the following requirements:

(a) The Permittee shall use a vapor collection system which directs all vapors from gasoline tank trucks to a closed flare thermal oxidizer. The vapor control system shall be in good working order and in operation at all times loading operations are being conducted.

(b) Displaced vapors and gases from gasoline tank trucks shall be vented only to the vapor control system.

(c) The source shall provide a means to prevent liquid drainage from the loading device when it is not in use or to accomplish complete drainage before the loading device is disconnected.

(d) All loading and vapor lines shall be equipped with fittings which make vapor-tight connections and which will be closed upon disconnection.

(e) If employees of the terminal are not present during loading, it shall be the responsibility of the owner of the transport to make certain the vapor control system is attached to the transport. The owner of the terminal shall take all reasonable steps to ensure that owners of transports loading at the terminal during unsupervised times comply with this requirement.

D.30.3 Leaks from Transports and Vapor Collection Systems [326 IAC 8-4-9]

Pursuant to 326 IAC 8-4-9, the Permittee shall comply with the following requirements:

(a) No gasoline transport that has a capacity of two thousand (2,000) gallons or more shall be filled or emptied unless the owner or operator of the gasoline transport completes the following:

(1) Perform annual leak detection testing before the end of the twelfth calendar month following the previous year's test. The testing shall be performed in accordance with the test procedures contained in Section E.16.

(2) Repairs the gasoline transport if the transport does not meet the criteria in (1), and retests the transport after repairs to prove compliance with the criteria in (1).

Demonstration of compliance with Section E.16 assures compliance with this condition.

(b) The annual compliance test data remain valid until the end of the twelfth calendar month following the test. The owner of the gasoline transport shall be responsible for compliance with the requirements in (a) and shall provide the Permittee with the most recent valid modified 40 CFR 60, Appendix A, Method 27 test results upon request. The Permittee shall take all reasonable steps, including reviewing the test date and tester's signature, to ensure that gasoline transports comply with the requirements in (a). Demonstration of compliance with Section E.16 assures compliance with this condition.

(c) The Permittee shall design and operate the vapor control system and gasoline loading equipment in a manner that prevents:

(1) Gauge pressure from exceeding four thousand five hundred (4,500) pascals (18 inches of H2O) and a vacuum from exceeding one thousand five hundred (1,500) pascals (6 inches of H2O) in the gasoline transport.

(2) Avoidable visible liquid leaks during loading.

(3) Within fifteen (15) days, repair and retest a vapor collection system that exceeds the limits in (1) and (2).

(d) IDEM, OAQ may, at any time, monitor a gasoline transport or vapor control system to confirm continuing compliance with (a) and (b).

(e) The Permittee shall maintain records of all certification testing. The records shall identify the following:

(1) The vapor collection and vapor control system

(2) The date of the test and, if applicable, retest.

(3) The results of the test and, if applicable, the retest.

The records shall be maintained in a legible, readily available condition for at least two (2) years after the date the testing and, if applicable, retesting were completed. The Permittee may comply with the requirements of this paragraph by complying with the requirements of 40 CFR 60.505(e), which are included in Section E.15.

(f) During compliance tests conducted under 326 IAC 3-6 (Stack Testing), the vapor control system shall be tested using 40 CFR 60, Subpart A, Method 21. The threshold for leaks shall be five hundred (500) parts per million methane for bulk gasoline terminals subject to 40 CFR 63, Subpart R. Demonstration of compliance with Section E.16 assures compliance with this condition.

D.30.4 Particulate Matter Limitation (PM) [326 IAC 6.8-1-2(b)(3)]

Pursuant to 326 IAC 6.8-1-2(b)(3)(Nonattainment Area Limitations) (formerly 326 IAC 6-1-2(b)(5)), the particulate matter content of natural gas burned in the 1.6 MMBtu per hour boiler shall be limited to 0.01 grains per dry standard cubic foot of natural gas.

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.30.5 Record Keeping Requirements

Pursuant to 40 CFR Part 63, Subpart CC and to comply with the requirements in Condition D.30.1, the Permittee shall comply with the record keeping requirements specified in Sections E.1 and E.16.

D.30.6 Reporting Requirements

Pursuant to 40 CFR Part 63, Subpart CC and to document compliance with the requirements in Condition D.30.1, the Permittee shall comply with the reporting requirements specified in Sections E.1 and E.16.

SECTION D.31 FACILITY OPERATION CONDITIONS - Cooling Tower

Facility Description [326 IAC 2-7-5(15)]

(ee) Cooling Towers, including the following:

(1) One (1) cooling tower (identified as Cooling Tower No.6), constructed in 1996, with a maximum capacity of 20,000 gallons of water per minute. Cooling Tower No.6 is located at the No.12 Pipestill.

(2) Cooling Towers (constructed prior to 1980) with controls installed as part of the CXHO project:

Cooling Tower	Recirculation Rate/Make-up rate (gallons/minute)	Control Devices
Cooling Tower 2*	50,000/1,285	high efficiency liquid drift eliminators
Cooling Tower 3	90,000/1,571	high efficiency liquid drift eliminators
Cooling Tower 4	44,000/1,085	high efficiency liquid drift eliminators

* Half of the Cooling Tower 2 modules were controlled prior to the CXHO Project. Contemporaneous to the CXHO Project the other modules will be controlled with high efficiency drift eliminators.

(3) Cooling Towers to be installed as part of the CXHO project:

Cooling Tower 7	21,000/451	high efficiency liquid drift eliminators
Cooling Tower 8	90,000/2956	high efficiency liquid drift eliminators

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.31.1 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3]

(a) In order to render 326 IAC 2-3 (Emission Offset) not applicable and pursuant to CP089-4822-00003, issued April 19, 1996, the average concentration of total dissolved solids (TDS) in the water input to Cooling Tower No.6 shall not exceed 3,300 mg/L based on a twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) In order to render 326 IAC 2-3 (Emission Offset) not applicable and pursuant to CP089-4822-00003, issued April 19, 1996, the VOC emissions from Cooling Tower No.6 shall not exceed 0.84 pounds per hour.

Compliance with these limits shall ensure~~s~~ that 326 IAC 2-3 does not apply to Cooling Tower No. 6.

(c) In order to render 326 IAC 2-2 and 326 IAC 2-1.1-5 not applicable, after the installation of the liquid drift eliminators on cooling towers 2, 3, 4, and the installation of towers 7 and 8, the average concentration of total dissolved solids (TDS) in the water input to Cooling Towers No. 2, 3, 4, 7, and 8 shall not exceed the following:

Cooling Tower	TDS (mg/L) per twelve (12) consecutive month period
2	1,627
3	1,147
4	1,645
7	1,163
8	1,163

(d) In order to render 326 IAC 2-3 (Emission Offset) not applicable, the VOC emissions from Cooling Towers No., 7 and 8 shall not exceed the following based on a 12 consecutive month average:

Cooling Tower	lb/hr
7	0.9
8	3.9

Compliance with the VOC, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for VOC, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

Compliance Determination Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.31.2 Operating Requirements

In order to demonstrate compliance with Condition D.31.1(c), the liquid drift eliminators shall be in operation and control PM and PM-10 from Cooling Towers 2, 3, 4, 7 and 8 at all times that these cooling towers are in operation.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.31.3 Compliance Monitoring Requirements [326 IAC 2-3]

(a) To monitor compliance with Condition D.31.1(a) and (c), the Permittee shall take weekly measurements of the total dissolved solids (TDS) in the water input to Cooling Towers No. 2, 3, 4, 6, 7 and 8. If the TDS limitation is exceeded, the Permittee shall perform quantitative water analyses and shall take the remedial action necessary to correct the problem.

(b) To monitor compliance with Condition D.31.1(b) and (d), the Permittee shall visually inspect the water going to Cooling Towers No. 2, 3, 4, 6, 7 and 8 for liquid VOC, including but not limited to the indication of a sheen, at least once per week. If VOC is observed, the Permittee will take the remedial action necessary to correct the problem.

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.31.4 Record Keeping Requirements [326 IAC 2-3]

(a) To document compliance with Condition D.31.1(a) and (c), and 31.3(a), the Permittee shall maintain records of the total dissolved solids (TDS) in the water input to Cooling Towers No. 2, 3, 4, 6, 7 and 8 and any remedial actions taken (including the date remedial actions were initiated).

(b) To document compliance with Condition D.31.1(b) and (d) and D.31.3(b), the Permittee shall maintain records of the visual inspects required by D.31.3(b) and any remedial actions taken (including the date remedial actions were initiated).

SECTION D.32 FACILITY OPERATION CONDITIONS - Asphalt Facility

Facility Description [326 IAC 2-7-5(15)]:

(ff) One (1) Asphalt Facility used to store, blend and transfer asphalt products. The facility has six blenders used for loading asphalt into railcars and trucks. Process heaters are used to keep certain tanks at the proper temperature for shipping. This facility includes the following emission sources and may also include insignificant activities listed in section A.4 of this permit:

(1) The following two (2) process heaters:

Process Heater ID	Heat Input Capacity (MMBtu/hr)	Fuel	Control Device
F-1 Asphalt Heater	12	Natural gas	none
F-2 Steiglitz Park Heater	28	Natural gas	none

(2) The following seven (7) asphalt storage tanks used to store volatile organic liquids that have a vapor pressure less than 0.75 psi:

Identification	Storage Capacity (gallons)	Year Constructed
125	3,108,000	1998
126	3,108,000	1999
127	3,108,000	2000
129	3,108,000	2003
150	1,386,000	1986
569	5,544,000	1981
613	8,866,200	1992

(3) The following twenty-five (25) asphalt storage tanks used to store volatile organic liquids that have a vapor pressure less than 0.5 psi.

Identification	Storage Capacity (gallons)	Year Constructed
78	1,814,400	1947
113	810,600	1944
114	810,600	1944
128	3,225,600	1971
148	810,600	1948
149	810,600	1948
153	932,400	1979
222	210,000	1955
223	210,000	1955
224	210,000	1955
225	361,200	1950
248	6,967,800	1973
249	6,967,800	1973
250	6,967,800	1971
251	6,967,800	1971
252	6,967,800	1972
253	6,967,800	1971
261	441,000	1973
262	441,000	1972
468	3,108,000	1956
571	5,040,000	1971

572	5,040,000	1971
609	5,649,000	1973
611	8,513,400	1973

(4) The following twenty-two (22) heated vertical storage tanks, each approved for construction in 2007, each with a fixed cone roof, and each in heavy liquid service, storing volatile organic liquids that have a vapor pressure less than 0.0435 psia, and exhausting to the atmosphere or to a biofilter system for odor and opacity control:

Tank ID	Liquid Stored	Date Approved for Construction	Tank Storage Capacity (gallons)	Maximum Throughput (gallons/year)	Vapor Pressure of Liquid at Storage Temperature (psia)	Exhaust ID
TK-3573	Trim Gas Oil	2007	966,000	20,160,000	< 0.0435	TK-3573
TK-SP-1	Residual Oil and/or Asphalt	2007	14,154,000	141,120,000	< 0.0435	biofilter
TK-SP-2	Residual Oil and/or Asphalt	2007	14,154,000	141,120,000	< 0.0435	biofilter
TK-SP-3	Trim Gas Oil	2007	2,268,000	16,800,000	< 0.0435	biofilter
TK-SP-4	Trim Gas Oil	2007	2,268,000	16,800,000	< 0.0435	biofilter
TK-LG-1	Asphalt	2007	4,746,000	50,400,000	< 0.0435	biofilter
TK-LG-2	Asphalt	2007	4,746,000	50,400,000	< 0.0435	biofilter
TK-LG-3	Asphalt	2007	4,746,000	50,400,000	< 0.0435	biofilter
TK-LG-4	Asphalt	2007	4,746,000	50,400,000	< 0.0435	biofilter
TK-LG-5	Asphalt	2007	4,746,000	50,400,000	< 0.0435	biofilter
TK-LG-6	Asphalt	2007	4,746,000	50,400,000	< 0.0435	biofilter
TK-LG-7	Asphalt	2007	4,746,000	50,400,000	< 0.0435	biofilter
TK-LG-8	Asphalt	2007	4,746,000	50,400,000	< 0.0435	biofilter
TK-LG-9	Asphalt	2007	4,746,000	50,400,000	< 0.0435	biofilter
TK-LG-10	Trim Gas Oil	2007	2,268,000	16,800,000	< 0.0435	biofilter
TK-LG-11	Trim Gas Oil	2007	2,268,000	16,800,000	< 0.0435	biofilter
TK-LG-12	Asphalt with Polymer	2007	2,100	420,000	< 0.0435	biofilter
TK-LG-13	Asphalt-Polymer Blend	2007	31,500	2,100,000	< 0.0435	biofilter
TK-LG-14	Polymer Finished Asphalt	2007	126,000	2,520,000	< 0.0435	biofilter
TK-LG-15	Polymer Finished Asphalt	2007	126,000	2,520,000	< 0.0435	biofilter
TK-LG-16	Polymer Finished Asphalt	2007	126,000	2,520,000	< 0.0435	biofilter
TK-LG-17	Polymer Finished Asphalt	2007	126,000	2,520,000	< 0.0435	biofilter

Under 40 CFR 60, Subpart UU, storage tanks TK-SP-1, TK-SP-2, TK-LG-1 through TK-LG-9, and TK-LG-12 through TK-LG-17 are each considered an affected facility.

Under 40 CFR 63, Subpart CC, storage tanks TK-3573, TK-SP-1 through TK-SP-4, TK-LG-1 through TK-LG-17 are each considered as Group 2 storage vessels that are part of the existing affected source.

(5) The following heated vertical storage tank, with a fixed cone roof, in heavy liquid service, storing volatile organic liquids that have a vapor pressure less than 0.0435 psia, and exhausting to the atmosphere:

Tank ID	Liquid Stored	Construction Date	Tank Storage Capacity (gallons)	Maximum Throughput (gallons/year)	Vapor Pressure of Liquid at Storage Temperature (psia)	Exhaust ID
TK-3570	Trim Gas Oil	1971	2,730,000	20,160,000	< 0.0435	TK-3570

Under 40 CFR 63, Subpart CC, storage tank TK-3570 is considered as a Group 2 storage vessel that is part of the existing affected source.

(6) one (1) truck loading rack, approved for construction in 2007, comprised of six (6) loading bays used for loading liquid asphalt product, with a total maximum loading capacity of 800,000 tons of asphalt product per year, exhausting to the atmosphere or to a biofilter system for odor control.

(7) one (1) rail car loading rack, approved for construction in 2007, comprised of twenty-eight (28) loading bays used for loading liquid asphalt product, with a total maximum loading capacity of 800,000 tons of asphalt product per year, exhausting to the atmosphere or to a biofilter system for odor control.

(8) Equipment leaks of VOC and HAP from valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, flanges and/or other connectors.

Under 40 CFR 60, Subpart GGGa, valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, flanges and/or other connectors in VOC service, are considered part of the existing affected source.

(9) The following five (5) natural gas-fired hot oil heaters, each approved for construction in 2007, and each considered an insignificant activity, as defined in 326 IAC 2-7-1(21)(G)(i)(AA)(aa):

Process Heater ID	Heat Input Capacity (MMBtu/hr)	Fuel	Control Device
H-SP-1	9.9	Natural gas	none
H-SP-2	9.9	Natural gas	none
H-LG-1	9.9	Natural gas	none
H-LG-2	9.9	Natural gas	none
H-LG-3*	9.9	Natural gas	none

*Hot oil heater H-LG-3 will exhaust to a steam generator that will be used to heat rejected loads of asphalt during unloading.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.32.1.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the Permittee must comply with the following PM_{10} emission limitations for the Asphalt facility process heaters:

Process Heater	PM_{10} Limit (lbs/MMBtu)	PM_{10} Limit (lbs/hour)
F-1 Asphalt Heater	0.0075	0.089
F-2 Steiglitz Park Heater	0.0075	0.209

D.32.1.2 Lake County PM_{10} (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), the Permittee must comply with the following filterable PM_{10} emission limitations for the Asphalt facility process heaters:

Process Heater	PM_{10} Limit (lbs/MMBtu)	PM_{10} Limit (lbs/hour)
F-1 Asphalt Heater	0.004	0.048
F-2 Steiglitz Park Heater	0.008	0.208

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.32.1.1 as part of the Indiana State Implementation Plan.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.32.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7- 4.1-3, the Permittee shall comply with the following sulfur dioxide emission limitations for the Asphalt Facility process heaters:

Process Heater	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)
F-1 Asphalt Heater	0.033	0.43
F-2 Steiglitz Heater	0.033	0.90

D.32.3 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the process heaters F-1 and F-2.

D.32.4 NSPS Requirements [326 IAC 12-1] [40 CFR 60, Subpart UU]

Pursuant to the 40 CFR 60.470, the Permittee shall comply with the requirements specified in Section E.17 for storage tanks 125, 126, 127, 129, 150, 569, 613, TK-SP-1, TK-SP-2, TK-LG-1 through TK-LG-9, and TK-LG-12 through TK-LG-17.

D.32.5 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2(a), the particulate matter emissions from the storage tanks TK-3573, TK-SP-1 through TK-SP-4, TK-LG-1 through TK-LG-17, and TK-3570, the hot oil heaters H-SP-1, H-SP-2, H-LG-1, H-LG-2, and H-LG-3, and the liquid asphalt truck and rail car loading racks shall each be limited to 0.03 grains per dry standard cubic foot.

D.32.6 NESHAP Requirements [40 CFR Part 63, Subpart CC] [326 IAC 20-16]

Pursuant to 40 CFR 63.640, the Permittee shall comply with the requirements specified in Section E.1 for storage tanks TK-3573, TK-SP-1 through TK-SP-4, TK-LG-1 through TK-LG-17, and TK-3570.

D.32.7 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGGa, the Permittee shall comply with the requirements specified in Sections E.25 and E.26 for valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, flanges and/or other connectors in VOC service.

D.32.8 Natural Gas Usage Limit [326 IAC 2-2] [326 IAC 2-3]

The total natural gas usage shall not exceed 255 million cubic feet per twelve (12) consecutive month period for hot oil heaters H-SP-1, H-SP-2, H-LG-1, H-LG-2, and H-LG-3. Compliance with this limit shall ensure compliance with the requirements of 326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset).

D.32.9 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP), in accordance with Section B - Preventive Maintenance Plan, of Part 70 Operating Permit No. T089-6741-00453, is required for the biofilter system. The Permittee shall prepare and maintain the PMP for the biofilter system on or before initial startup of the biofilter system.

Compliance Determination Requirements

D.32.10 Operating Requirement

Pursuant to SPM 089-15202-00003, issued April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel in the Steiglitz Park Process Heater F-2 and the F-1 Asphalt Heater.

D.32.11 Operating Requirement

Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.32.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

D.32.12 Opacity Control

In order to comply with Condition D.32.4 (40 CFR Part 60, Subpart UU), opacity from storage tanks TK-SP-1, TK-SP-2, TK-LG-1 through TK-LG-9, and TK-LG-12 through TK-LG-17 shall be controlled by the biofilter system at all times that the storage tanks are in operation.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)] [326 IAC 2-7-6(1)]

D.32.13 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.32.14 Volatile Organic Liquid Storage Vessels [326 IAC 8-9]

(a) Pursuant to 326 IAC 8-9-6(a) and (b), the Permittee shall maintain the following information for storage tanks 125, 126, 127, 129, 150, 569, 613, 78, 113, 114, 128, 148, 149, 153, 222, 223, 224, 225, 248, 249, 250, 251, 252, 253, 261, 262, 468, 571, 572, 609, 611, TK-3573, TK-SP-1 through TK-SP-4, TK-LG-1 through TK-LG-17, and TK-3570:

(1) The vessel identification number.

(2) The vessel dimensions.

(3) The vessel capacity.

The Permittee shall maintain records described in (1) through (3) of this condition for the life of the vessel.

(b) Pursuant to 326 IAC 8-9-6(h), the Permittee shall maintain a record and notify IDEM, OAQ within thirty (30) days when the maximum true vapor pressure of the liquid stored in vessels 125, 126, 127, 129, 150, 569, 613, TK-3573, TK-SP-1 through TK-SP-4, TK-LG-1 through TK-LG-11, TK-LG-14 through TK-LG-17, or TK-3570 exceeds seventy-five hundredths (0.75) psia.

D.32.15 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.32.2, and D.32.10, the Permittee shall maintain a daily record of the following for the F-1 and F-2 process heaters:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.32.1, the Permittee shall maintain records for the Asphalt Heater F-1 and the Steiglitz Park Heater F-2 as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.32.3, the Permittee shall maintain records as specified in Section E.2.

(d) Pursuant to 40 CFR 60, Subpart UU and to document compliance with Condition D.32.4, the Permittee shall maintain records as specified in Section E.17.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.32.6, the Permittee shall keep records as specified in Section E.1.

(f) Pursuant to 40 CFR 60, Subpart GGGa and to document compliance with Condition D.32.7(b), the Permittee shall keep records as specified in Sections E.25 and E.26.

(g) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.32.7(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(h) To document compliance with Condition D.32.8, the Permittee shall record the total natural gas usage for hot oil heaters H-SP-1, H-SP-2, H-LG-1, H-LG-2, and H-LG-3 on a monthly basis;

D.32.16 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.32.2 and D.32.11, the Permittee shall submit a report to IDEM, OAQ department within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, for the F-1 Asphalt Heater and F-2 Steiglitz Heater.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.32.3, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 40 CFR 60, Subpart UU and to document compliance with Condition D.32.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.17.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.32.6, the Permittee shall submit reports as specified in Section E.1.

(e) Pursuant to 40 CFR 60, Subpart GGGa and to document compliance with Condition D.32.7(b), the Permittee shall submit to IDEM, OAQ the reports specified in Sections E.25 and E.26.

(f) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.32.7(a), the Permittee shall submit reports as specified in the LDAR plan.

(g) A quarterly summary of the information to document compliance with Condition D.32.8 shall be submitted to the addresses listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

SECTION D.33 FACILITY OPERATION CONDITIONS - Cogen Steam Transfer Line

Facility Description [326 IAC 2-7-5(15)]:

(gg) One (1) pipeline (Cogen Steam Transfer Line) connecting BP's boilers (identified as emission units 501 and 503) with Whiting Clean Energy's heat recovery steam operator. The pipeline is used to exchange steam between the two facilities. The pipeline was constructed in 2001.

(hh) One (1) pipeline (US Steel Stream Transfer Line) connecting BP's steam header with US Steel East Chicago (Plant ID #089-00300). This pipeline was constructed 2005 through 2006 and is used to transfer steam from BP to US Steel.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.33.1 Operational Limits

Pursuant to MSM 089-14239-00003, issued May 11, 2001, Joint Agreement Stay Cause No. 01-A-J-2731, issued May 20, 2003, and Administrative Amendment 089-21879-00003, issued November 18, 2005, the Permittee shall comply with the following requirements:

(a) The maximum amount of steam BP shall accept from Whiting Clean Energy is 13,200 tons per day. The maximum amount of steam BP shall supply to Whiting Clean Energy and US Steel is 8,400 tons per day. In all cases, the net steam flow over any 365 day period, from Whiting Clean Energy to BP shall be positive.

(b) The amount of steam BP accepts from Whiting Clean Energy plus the amount of steam produced from units 501 and 503 shall not exceed 34,560 tons per day.

Compliance with these limitations makes the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) not applicable to the installation of the pipeline.

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.33.2 Recordkeeping Requirements

Pursuant to MSM 089-14239-00003, issued May 11, 2001 and the Joint Agreement Stay Cause No. 01-A-J-2731, issued May 20, 2003, and Administrative Amendment 089-21879-00003, issued November 18, 2005 and to document compliance with Condition D.33.1, the Permittee shall maintain the following records:

(a) Records of the average annual net flow rate from Whiting Clean Energy to BP, computed on a rolling 365-day basis;

(b) Records of the amount of steam produced by units 501 and 503 each day;

(c) Records of the amount of steam BP accepts from Whiting Clean Energy each day; and

(d) Records of the amount of steam BP supplies to Whiting Clean Energy and US Steel each day.

D.33.3 Reporting Requirements

A quarterly summary of the information to document compliance with Condition D.33.1 shall be submitted to the addresses listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

SECTION D.34 FACILITY OPERATION CONDITIONS - Marine Dock Facility

Facility Description [326 IAC 2-7-5(15)]

(ii) One (1) Marine Dock Facility used to store and transfer products. The facility has three dock berths. A process heater is used to keep certain tanks at the proper temperature for shipping. As part of the CXHO Project, a vapor recovery/control system will be installed on the Marine Dock Loading operations to control emissions from gasoline loading. This facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) natural gas-fired process heater (identified as Marine Dock Heater F-100), having a maximum heat input capacity of 7 MMBtu per hour.

(2) One (1) storage tank (identified as BT-1), constructed in 1990, with a maximum storage capacity of 706,000 gallons and used to store petroleum hydrocarbons with a vapor pressure less than 15 psia. The tank is equipped with a fixed roof and an internal floating roof.

(3) One storage tank (BT-002), constructed in 1968, permitted for modification per SPM 089-25488-00453, with a maximum storage capacity of 874,944 gallons, used to store petroleum hydrocarbons with a vapor pressure less than 15 psia, with a fixed roof and an internal floating roof.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.34.1.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-3-6]

Pursuant to 326 IAC 6.8-2-6(b) (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the F-100 marine docks distillate heater shall have the following emission limits:

(a) Only natural gas shall be burned as fuel; and

(b) The PM10 emissions shall not exceed 0.0075 pounds per million Btu heat input and 0.052 pounds per hour.

D.34.1.2 Lake County PM_{10} (Filterable) Emission Limitations [326 IAC 6.8-3-6]

Pursuant to 326 IAC 6.8-6-3 (formerly 326 IAC 6-1-10.1(h)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), the Permittee shall comply with the following requirements for process heater F-100:

(a) Only natural gas shall be burned as fuel; and

(b) The filterable PM10 emissions shall not exceed 0.003 pounds per million Btu heat input and 0.020 pounds per hour.

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.1.1.1 as part of the Indiana State Implementation Plan.

D.34.2 Emission Offset [326 IAC 2-3] Minor Limit

In order to render 326 IAC 2-3 not applicable, the Permittee shall comply with the following limits for gasoline loading operations at the marine loading dock:

(a) The VRU/VCU shall be installed and operated as part of the CXHO project.

(b) After the installation of the Vapor Recover Unit (VRU) or Vapor Capture Unit (VCU) on the marine loading dock, the emissions of VOC during gasoline loading shall not exceed 10 milligrams per liter (mg/L) of gasoline loaded.

(c) After the installation of the Vapor Recover Unit (VRU) or Vapor Capture Unit (VCU) on the marine loading dock, the gasoline loaded shall not exceed 4,000,000 barrels per 12 consecutive month period, with compliance determined at the end of each month.

(d) The additional NOx and CO emissions from the VRU/VCU shall not exceed 5.6 tons and 2.2 tons per 12 consecutive month period, respectively, with compliance determined at the end of each month,

Compliance with the VOC, NOx and CO emissions limit, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for VOCand CO for the CXHO project remain below the significant, rendering 326 IAC 2-3 not applicable for these pollutants.

D.34.3 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems and oil-water separators.

D.34.4 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) and Benzene [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAPs from pumps, valves, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

D.34.5 Standards for Marine Tank Loading [326 IAC 20-17] [40 CFR 63, Subpart Y] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC and Y, the Permittee shall comply with the requirements specified in Section E.1 and E.12 for the Marine Dock Facility.

D.34.6 Petroleum Liquid Storage Facilities [326 IAC 8-4-3]

Pursuant to 326 IAC 8-4-3(b), the Permittee shall not permit the storage of a VOC with a true vapor pressure greater than 1.52 psia (10.5 kPa) in a fixed roof tank with a capacity greater than 39,000 gallons unless:

(a) The tank has been retrofitted with an internal floating roof equipped with a closure seal, or seals, to close the space between the roof edge and tank wall unless the source has been retrofitted with equally effective alternate control which has been approved,

(b) The facility is maintained such that there are no visible holes, tears or other opening in the seal or any seal fabric or materials,

(c) All openings, except stub drains, are equipped with covers, lids or seals such that:

(1) the cover, lid or seal is in the closed position at all times except when in actual use;

(2) automatic bleeder vents are closed at all times except when in actual use;

(3) rim vents if provided, are set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

D.34.7 VOC and HAP Emissions From Storage Vessels [326 IAC 12] [40 CFR 60, Subpart Kb] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 40 CFR 60, Subpart Kb and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.9 for storage tanks BT-1 and BT-002.

(b) Pursuant to 40 CFR 63.640(n)(1), a Group 1 or Group 2 storage vessel that is subject to 40 CFR 63, Subpart CC and to the provisions of 40 CFR 60, Subpart Kb is required to comply only with the requirements of 40 CFR 60, Subpart Kb except as provided in 40 CFR 63.640(n)(8), which are listed in Section E.1.

Compliance Determination Requirements

D.34.8 Operating Requirement

Pursuant to SSM 089-14630-00003, issued on November 30, 2001, fuel oil shall not be used as fuel for process heater F-100, effective June 1, 2003.

D.34.9 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

(a) Within 180 days of the installation of the VRU or VCU at the marine loading dock, in order to demonstrate compliance with Condition D.34.2, the Permittee shall perform VOC testing at the outlet of the VRU/VCU when loading gasoline utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C - Performance Testing. This test shall be repeated at least once every five years from the date of the previous valid compliance demonstration.

(b) Compliance with the emissions limit for the VRU/VCU shall be determined as follows:

$$T = \left(\sum_{i=1}^{n} T_i\right) / n$$

Where:

T = average of IDEM approved stack test results over the previous 12 month period
T_i = average of multiple runs during Test #i
n = number of IDEM approved stack tests during previous 12 month period

D.34.10 Operating Requirement

After the installation of the VRU/VCU at the marine loading dock, in order to demonstrate compliance with Condition D.34.2, the VRU/VCU shall be in operation and control VOC emissions at all times gasoline loading is being performed at the marine loading dock.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.34.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.34.12 Record Keeping Requirements

(a) To document compliance with Condition D.34.8 the Permittee shall maintain records of the type of fuel burned in Process Heater F-100.

(b) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.34.4(a), the Permittee shall comply with the record keeping requirements in the LDAR Plan.

(c) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.34.4(b), the Permittee shall comply with the record keeping requirements in Sections E.1 and E.4.

(d) Pursuant to 326 IAC 8-4-3(d) and to document compliance with Condition D.34.6, the Permittee shall maintain the following records for storage tanks BT-1 and BT-002:

(1) The type of petroleum liquid stored;

(2) The maximum true vapor pressure to the liquid as stored; and

(3) The results of inspections performed on the storage vessel.

(e) Pursuant to 40 CFR 60, Subpart Kb and 40 CFR 63, Subpart CC and to document compliance with Condition D.34.7, the Permittee shall comply with the record keeping requirements in Sections E.1 and E.9.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.34.3, the Permittee shall keep records as specified in Sections E.1 and E.3.

(g) Pursuant to 40 CFR 63, Subparts CC and Y and to document compliance with Condition D.34.5, the Permittee shall maintain records of as specified in Sections E.1 and E.12.

(d) In order to demonstrate compliance with Condition D.34.2, the Permittee shall maintain records of barrels of gasoline loaded each month at the marine loading dock.

D.34.13Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.34.4(a), the Permittee shall comply with the reporting requirements in the LDAR Plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.34.4(b), the Permittee shall comply with the reporting requirements specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 60, Subpart Kb and 40 CFR 63, Subpart CC and to document compliance with Condition D.34.7, the Permittee shall comply with the reporting requirements specified in Sections E.1 and E.9.

(d) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.34.3, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(e) In order to demonstrate compliance with Condition D.34.2, following the installation of the VRU/VCU at the marine loading dock, the Permittee shall submit quarterly reports of the barrels of gasoline loaded at the marine loading dock. The report submitted by the Permittee does require the certification by the “Responsible Official” as defined by 326 IAC 2-7-1(34).

SECTION D.35 FACILITY OPERATION CONDITIONS – Hydrocarbon Flares

Facility Description [326 IAC 2-7-5(15)]

(jj) The refinery operates ten hydrocarbon flares. The PIB flare is operated by INEOS. The flares are used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

The flares are identified as follows:

Flare	Stack ID.	Date of Installation	Dimensions	Process Units Normally Controlled by the Flare System *	Maximum Capacity (MMBtu/hr)	Pilot Fuel Type
4UF Flare	224-06	1972	H = 200 ft, D = 2.5 ft.	ARU, CFU, BOU, 4UF	15,000	Fuel Gas and Natural Gas
FCU flare	230-02	1945	H = 200 ft. D = 2.0 ft.	FCU 600	5620	Fuel Gas and Natural Gas
UIU Flare	220-04	1958	H = 199.5 ft. D = 2.5 ft.	ISOM, 3UF, 2TP, CRU	7550	Fuel Gas and Natural Gas
VRU Flare	241-01	Unknown	H = 200 ft. D = 2.0 ft.	VRU 100,VRU200, VRU 300, FCU 500	1596	Fuel Gas and Natural Gas
Alky Flare	140-01	1961	H = 199.5 ft D = 2.5 ft.	PCU, Alky	3920	Fuel Gas and Natural Gas
SRU Flare	162-03	1971	H = 300 ft. D = 1.5 ft.	SRU	688	Fuel Gas and Natural Gas
DDU Flare	698-02	1993	H = 200 ft. D = 1.5 ft.	DDU, HU, Coker, DHT	6000	Fuel Gas and Natural Gas
LPG Flare	604-01	1986	H = 50 ft. D = 1.2 ft.	LPG storage vessels and loading facilities	30	LPG
PIB Flare**	2	1982	H = 250 ft. D = 3.0 ft.	RGP/PGP Loading Rack	540,000 lb/hr	Fuel Gas and Natural Gas
GOHT Flare***	802-03	Installed as Part of CXHO	H = 316 ft. D = 3.5 ft	GOHT	TBD	Fuel Gas and Natural Gas
South Flare***	800-04	Installed as Part of CXHO	H = 350 ft. D = 5 ft	New Coker (#2 Coker), 12PS, Sulfur Recovery Complex	TBD	Fuel Gas and Natural Gas

* - During emergencies or flare outages, some emission units or streams may be controlled by an alternate flare system that complies with the same applicable requirements as the flare normally used to control the emissions for those units.

**** -** Owned and operated by INEOS USA, LLC. (Plant I.D. 089-00076).

***** - Flares are equipped with a flare gas recovery system. Under normal operation the recovered gas streams will be sent to vapor recovery/treating area for removal of H_2S and heavy components before being utilized in the refinery fuel gas system.**

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.35.1 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for the GOHT Flare and the South Flare:

(a) The emissions of NOx shall not exceed 100 pounds per million cubic feet and 0.068 pounds per million BTU of pilot and purge gas burned.

(b) The emissions of VOC shall not exceed 5.5 pounds per million cubic feet and 0.14 pounds per million BTU of pilot and purge gas burned.

(c) The emissions of CO shall not exceed 84 pounds per million cubic feet and 0.37 pounds per million BTU of pilot and purge gas burned.

(d) The emissions of SO2 shall not exceed 0.6 pounds per million cubic feet of pilot gas burned.

(e) The emissions of SO2 shall not exceed 13.3 pounds per million cubic feet of purge gas burned.

(f) The emissions of PM and PM-10 shall not exceed 1.9 and 7.6 pounds per million cubic feet of pilot and purge gas burned.

(g) The Permittee shall comply with the following fuel usage limits:

Flare ID	Fuel Usage Limit (10^3 cubic feet per 12 consecutive month period)
GOHT-pilot	3,679.2
GOHT-purge	24,703.2
South flare-pilot	3,679.2
South flare-purge	28,908.0

Compliance with the fuel usage limits and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levelst, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.35.2 Standards for Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Section E.1 for the UIU, VRU, GOHT, South and Alky flares relating to the control of process vents.

D.35.3 Equipment Leaks of Benzene [326 IAC 14][40 CFR 61, Subpart J]

Pursuant to 40 CFR 61, Subpart J, the Permittee shall comply with the requirements specified in Section E.5 for control device standards for the 4UF Flare.

D.35.4 Equipment Leaks of VOC [326 IAC 12] [40 CFR 60, Subpart GGG] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 40 CFR 60, Subpart GGG, the Permittee shall comply with the control device standards specified in Section E.13 for the 4UF, UIU, Alky, and DDU flares.

(b) Pursuant to 40 CFR 60, Subpart GGGa, the Permittee shall comply with the control device standards specified in Section E.25 for GOHT and South flares.

D.35.5 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

(a) Pursuant to 40 CFR 60, Subpart J, the Permittee shall comply with the requirements specified in Section E.2 for the DDU Flare, GOHT flare, South flare and LPG Flare, except as specified in paragraphs (b).

(b) To demonstrate compliance with paragraph (a) of this condition, the Permittee shall operate the LPG Flare in compliance with the approved alternative monitoring requirements in Condition D.35.7.

D.35.6 Compliance Monitoring Requirements for the LPG Flare [326 IAC 12] [40 CFR 60, Subpart J]

The Permittee shall comply with the following alternative compliance monitoring requirements for the LPG Flare:

(a) The Permittee shall burn only certified commercial grade LPG in the LPG Flare.

(b) On May 13, 2004, the Permittee completed a detection tube sampling and analysis of the gas stored at the LPG storage facilities and determined that the total sulfur content of the gas is 34 ppm. No further testing is required.

(c) If the gas stream composition changes or if the gas stream will no longer be required to meet product or pipeline specifications, then the gas stream must be resubmitted for approval.

D.35.7 Operating Requirements for the Flares

The Permittee may route emissions to an alternate flare during emergencies or flare outages. The alternative flare shall be in compliance with the same requirements applicable to the flare normally used to control the emissions, except in cases of emergencies or malfunctions. Use of a flare as part of normal operation, which is not in compliance with the same applicable requirements as the flare normally used to control emissions, shall require prior approval by IDEM, OAQ.

D.35.8 NESHAP for Petroleum Refineries [40 CFR 63, Subpart UUU]

Pursuant to 40 CFR 63, Subpart UUU, the Permittee shall comply with the requirements specified in Section E.10 for the 4UF and UIU flares.

D.35.9 Continuous Monitoring – GOHT and South Flare [326 IAC 2-2]

The Total Reduced Sulfur continuous emission monitoring systems (CEMS) for the GOHT and South Flares shall be calibrated, maintained, and operated in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. For purposes of demonstrating compliance with Condition D.0.1, the SO2 emissions from the GOHT and South Flares shall be calculated as provided in Paragraph (g) of Condition D.0.1 based on the conversion of one mole of sulfur in the gas to one mole of SO2.

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.35.10 Record Keeping Requirements

(a) To document compliance with Condition D.35.2, pursuant to 40 CFR 63, Subpart CC, the Permittee shall maintain the records as specified in Section E.1.

(b) Pursuant to 40 CFR 61, Subpart J and to document compliance with Condition D.35.3, the Permittee shall keep records as specified in Section E.5.

(c) Pursuant to 40 CFR 60, Subparts GGG and GGGa and to document compliance with Condition D.35.4, the Permittee shall maintain the records as specified in Sections E.13 and E.25.

(d) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.35.5, the Permittee shall keep records as specified in Section E.2.

(e) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition D.35.8, the Permittee shall keep records as specified in Section E.10.

(f) In order to demonstrate compliance with Condition D.35.1(e), the Permittee shall maintain records of fuel usages at the GOHT and South flares.

D.35.11 Reporting Requirements

(a) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.35.2, the Permittee shall submit reports as specified in Section E.1.

(b) Pursuant to 40 CFR 61, Subpart J and to document compliance with Condition D.35.3, the Permittee shall submit reports as specified in Section E.5.

(c) Pursuant to 40 CFR 60, Subparts GGG and GGGa and to document compliance with Condition D.35.4, the Permittee shall submit reports as specified in Sections E.13 and E.25.

(d) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.35.5, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(e) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition D.35.8, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.10.

(f) In order to demonstrate compliance with Condition D.35.1, the Permittee shall submit quarterly reports for pilot gas and purge gas usages at the GOHT and South flares. The report submitted by the Permittee does require the certification by the “Responsible Official” as defined by 326 IAC 2-7-1(34).

SECTION D.36 FACILITY OPERATION CONDITIONS – OSBL

Facility Description [326 IAC 2-7-5(15)]

(kk) The OSBL area includes the pipe alleys, laboratory dock and waste transfer pad. The pipe alleys contain pipes that transfer hydrocarbon streams from one process unit to another or to storage. This facility includes leaks from process equipment, including open-ended valves or lines and flanges. This facility also contains area drains and an oil/water separator. This facility may include insignificant activities listed in section A.4 of this permit."

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.36.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Prior to start-up of the new coker (#2 Coker), BP shall make a determination as to whether 40 CFR 60, Subpart GGGa has been triggered by component changes made on the OSBLas a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.36.2 Wastewater / Waste Streams [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, subpart CC specified in Section E.1.

(d) Pursuant to 40 CFR 63, Subpart DD, the Permittee shall comply with the requirements under 40 CFR 63.680(d) specified in Section E.14 of the permit for off-site wastewater received at the refinery.

Compliance Monitoring Requirements

D.36.3 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.36.4 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.36.1(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.36.1(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.36.2(a), the Permittee shall keep records as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.36.2(b), the Permittee shall keep records as specified in Section E.6.

D.36.5 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.36.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.36.1(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.36.2(a), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.36.2(b), the Permittee shall submit reports as specified in Section E.6.

SECTION D.37 FACILITY OPERATION CONDITIONS – Distillate Hydrotreating Unit

Facility Description [326 IAC 2-7-5(15)]:

(ll) The Distillate Hydrotreating (DHT) Unit, identified as Unit ID 720 and rated at 45,000 barrels per day, which removes sulfur from petroleum distillates. Distillate feed is mixed with hydrogen, heated in a process furnace and passed over a catalyst bed to convert sulfur compounds to H_2S. The DHT Unit was constructed in 2005/2006 and includes the following emission units:

(1) DHT Unit Heater B-601, rated at 20 MMBtu per hour and constructed in May 2005. As part of the CXHO Project, DHT Unit Heater B-601 will be replaced with a 41.9 MMBtu per hour natural gas fired heater, identified as B-601A. NO_X emissions are controlled by ultra low-NO_X burners having an emission rate of 0.04 pounds per million Btu heat input or less. Emissions are exhausted to a stack identified as 720-01.

(2) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

The DHT Unit shares the DDU Flare, used to control VOC emissions during emergency situations, unit startups and shutdowns.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.37.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from Heater B-601 (until shutdown) and B-601A shall not exceed 0.03 grains per dry standard cubic foot.

D.37.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7-4.1-1]

Pursuant to 326 IAC IAC 7-4.1-1, the Permittee shall burn only natural gas in DHT Heater B-601 (until shutdown) and B-601A.

D.37.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for heater B-601A:

(a) The emissions of NOx shall not exceed 7.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(b) The emissions of CO shall not exceed 7.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(c) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(d) The emissions of PM and PM-10 shall not exceed 0.0019 and 0.0075 pounds per million BTU, respectively.

(e) The firing rate shall not exceed 367,044 million BTU per 12 consecutive month period, with compliance determined at the end of each month.

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.37.4 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP)[326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]{40 CFR 60, Subpart GGG]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.4, and E.13 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.37.5 Wastewater / Waste Streams [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and aggregate facilities subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and aggregate facilities subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.37.6 Emission Offset [326 IAC 2-3]

(a) Equipment leaks shall comply with the standards in 40 CFR 60 Subpart GGG and 40 CFR 63 Subpart CC, as applicable for components in gas/vapor service and light liquid service, except that a more stringent definition of a leak shall apply to valves and flanges. An instrument reading of 500 parts per million (ppm) or greater shall constitute a leak for valves and flanges.

(b) All emissions from pressure relief devices and compressor seal systems shall be vented to a flare and burned as fuel.

(c) Nitrogen oxide emissions from Process Heater B-601 shall be controlled by ultra low-NO_X burners having an emission rate of 0.04 pounds per million Btu heat input or less.

The requirements in paragraphs (a) through (c) of this condition render the requirements of Emission Offset (326 IAC 2-3) not applicable.

Compliance Determination Requirements

D.37.7 Testing Requirements [326 IAC 2-7-6(1),(6)][326 IAC 2-1.1-11]

(a) Compressors in hydrogen service are exempt from the requirements of 40 CFR 60.592 and 40 CFR 63.698(a) and (c) if the Permittee demonstrates that a compressor is in hydrogen service. The Permittee may use engineering judgment to demonstrate that the percent hydrogen content exceeds 50 percent by volume. In the event that OAQ does not agree, OAQ reserves the right to require testing in accordance with 40 CFR 60.593(b)(1) and 40 CFR 63.698(g)(2)(i)(A).

(b) Compliance with the limits in Condition D.37.3(c) and (d) shall be demonstrated as specified in Condition D.0.3.

D.37.8 Continuous Emissions Monitoring

The CO and NOx Continuous Emissions Monitors (CEMs) for heater B-601A shall be calibrated, maintained, and operated for determining compliance with CO and NOx emissions limits for the heater B-601a in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.37.9 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.37.10 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.37.4(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Condition D.37.4(b), the Permittee shall keep records as specified in Sections E.1, E.4, and E.13.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.37.5(a), the Permittee shall keep records as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.37.5(b), the Permittee shall keep records as specified in Section E.6.

(e) In order to demonstrate compliance with Condition D.37.3, the Permittee shall maintain records of the monthly firing rates at B-601A.

(f) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.37.8, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.37.11 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.37.4(a), the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(b) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Conditions D.37.6(b), the Permittee shall submit reports as specified in Section E.1, E.4, and E.13.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.37.5(a), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.37.5(b), the Permittee shall submit reports as specified in Section E.6.

(e) In order to demonstrate compliance with Condition D.37.3, the Permittee shall submit a quarterly summary of the monthly firing rates at heater B-601A to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(f) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.37.3 and D.37.8, the Permittee shall submit reports of excess CO and NOx emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.38 FACILITY OPERATION CONDITIONS – Degreasing

Facility Description [326 IAC 2-7-5(15)]:

Insignificant Activities

(l) Degreasing operations that do not exceed 145 gallons per twelve (12) months, except if subject to 326 IAC 20-6 [326 IAC 2-7-1(21)(G)(vi)(CC)] [326 IAC 8-3].

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.38.1 Cold Cleaner Operations [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Operations), for cold cleaning operations, the Permittee shall:

(a) Equip the cleaner with a cover;

(b) Equip the cleaner with a facility for draining cleaned parts;

(c) Close the degreaser cover whenever parts are not being handled in the cleaner;

(d) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases;

(e) Provide a permanent, conspicuous label summarizing the operation requirements;

(f) Store waste solvent only in covered containers and not dispose of waste solvent or transfer it to another party, in such a manner that greater than twenty percent (20%) of the waste solvent (by weight) can evaporate into the atmosphere.

D.38.2 Cold Cleaner Degreaser Operation and Control [326 IAC 8-3-5]

(a) Pursuant to 326 IAC 8-3-5(a) (Cold Cleaner Degreaser Operation and Control), for cold cleaner degreaser operations without remote solvent reservoirs, the Permittee shall ensure that the following requirements are met:

(1) Equip the degreaser with a cover. The cover must be designed so that it can be easily operated with one (1) hand if:

(A) The solvent volatility is greater than two (2) kiloPascals (fifteen (15) millimeters of mercury or three-tenths (0.3) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F));

(B) The solvent is agitated; or

(C) The solvent is heated.

(2) Equip the degreaser with a facility for draining cleaned articles. If the solvent volatility is greater than four and three-tenths (4.3) kiloPascals (thirty-two (32) millimeters of mercury or six-tenths (0.6) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F)), then the drainage facility must be internal such that articles are enclosed under

the cover while draining. The drainage facility may be external for applications where an internal type cannot fit into the cleaning system.

(3) Provide a permanent, conspicuous label which lists the operating requirements outlined in subsection (b).

(4) The solvent spray, if used, must be a solid, fluid stream and shall be applied at a pressure which does not cause excessive splashing.

(5) Equip the degreaser with one (1) of the following control devices if the solvent volatility is greater than four and three-tenths (4.3) kiloPascals (thirty-two (32) millimeters of mercury or six-tenths (0.6) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F)), or if the solvent is heated to a temperature greater than forty-eight and nine-tenths degrees Celsius (48.9°C) (one hundred twenty degrees Fahrenheit (120°F)):

(A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.

(B) A water cover when solvent is used is insoluble in, and heavier than, water.

(C) Other systems of demonstrated equivalent control such as a refrigerated chiller of carbon adsorption. Such systems shall be submitted to the U.S. EPA as a SIP revision.

(b) Pursuant to 326 IAC 8-3-5(b) (Cold Cleaner Degreaser Operation and Control), the owner or operator of a cold cleaning facility construction of which commenced after July 1, 1990, shall ensure that the following operating requirements are met:

(1) Close the cover whenever articles are not being handled in the degreaser.

(2) Drain cleaned articles for at least fifteen (15) seconds or until dripping ceases.

(3) Store waste solvent only in covered containers and prohibit the disposal or transfer of waste solvent in any manner in which greater than twenty percent (20%) of the waste solvent by weight could evaporate.

SECTION D.39 FACILITY OPERATION CONDITIONS – Fuel Dispensing Facility

Facility Description [326 IAC 2-7-5(15)]:

(i) One (1) fuel dispensing operation, constructed in 2005, dispensing less than or equal to 1,300 gal/day into motor vehicle fuel tanks and with emissions less than the insignificant activity emission thresholds in 326 IAC 2-7-1(21)(A) through (C). The dispensing facility consists of a vapor balance system to control emissions and the following two (2) storage tanks [326 IAC 8-4-6]:

(A) One (1) gasoline storage tank, constructed in 2005, having a maximum storage capacity of 12,000 gallons.

(B) One (1) diesel storage tank, constructed in 2005, having a maximum storage capacity of 6,000 gallons.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.39.1 Volatile Organic Compounds [326 IAC 8-4-6(b)]

Pursuant to 326 IAC 8-4-6(b), the Permittee shall not allow the transfer of gasoline between and transport and any storage tank unless such tank is equipped with the following:

(a) A submerged fill pipe.

(b) Either a pressure relief valve set to release at no less than 0.7 pounds per square inch or an orifice of 0.5 inch in diameter.

(c) A vapor balance system connected between the tank and the transport, operating according to the manufacturer's specifications.

D.39.2 Volatile Organic Compounds [326 IAC 8-4-6(e)]

Pursuant to 8-4-6(e), Permittee shall not cause or allow the dispensing of motor vehicle fuel at any time unless all motor vehicle fuel dispensing operations are equipped with and utilize a certified vapor collection and control system which is properly installed and operated as follows:

(a) No vapor collection and control system shall be installed, used, or maintained unless the system has been certified by CARB and meets the testing requirements specified in Condition D.39.3.

(b) The vapor collection and control system utilized shall be maintained in accordance to its certified configuration and with the manufacturer's specification and maintenance schedule.

(c) No elements or components of a vapor collection and control system shall be modified, removed, replaced, or otherwise rendered inoperative in a manner which prevents the system from performing in accordance with its certification and design specifications.

(d) A vapor collection and control system shall not be operated with defective, malfunctioning, missing, or noncertified components. The following requirements apply to a vapor collection and control system:

(A) All parts of the system which can be visually inspected must be checked daily by the operator of the facility for the following malfunctions:

(i) Absence or disconnection of any component required to be used to certify the system.

(ii) A vapor hose which is crimped or flattened such that the vapor passage is blocked or severely restricted.

(iii) A nozzle boot which is torn in either of the following manners:

(AA) A triangular shaped or similar tear one-half (½) inch or more to a side or a hole one-half (½) inch or more in diameter or length.

(BB) Slit one (1) inch or more in length.

(iv) A faceplate or flexible cone which is damaged in the following manner:

(AA) For balance nozzles and nozzles for aspirator and educator assist type systems, damage shall be such that the capability to achieve a seal with a fill pipe interface is affected for one-fourth (¼) of the circumference of the faceplate (accumulated).

(BB) For nozzles for vacuum assist type systems that use a cone, having more than one-fourth (¼) of the flexible cone missing.

(v) A nozzle shutoff mechanism which malfunctions in any manner.

(vi) A vacuum producing device which is inoperative.

(B) Any defect in the system which is discovered in inspections required by paragraph (A) of this condition will require the immediate shutdown of the affected pumps until proper repairs are made.

(C) A signed daily log of the daily inspection required by paragraph (A) of this condition shall be maintained at the facility.

(D) One (1) operator or employee of the gasoline dispensing facility shall be trained and instructed annually in the proper operation and maintenance of a vapor collection and control system.

(E) Instructions shall be posted in a conspicuous and visible place within the motor vehicle fuel dispensing area for the system in use at that station. The instructions shall clearly describe how to fuel vehicles correctly with the vapor recovery nozzles utilized at that station. The instructions shall also include a warning that repeated attempts to continue dispensing motor vehicle fuel after the system has indicated that the vehicle fuel tank is full, may result in a spillage of fuel.

Compliance Determination Requirements

D.39.3 Volatile Organic Compounds [326 IAC 8-4-6(l)]

(a) Pursuant to 326 IAC 8-4-6(l), the vapor collection and control system shall be retested for vapor leakage and blockage, and successfully pass the test, at least every five (5) years or upon major system replacement or modification. A major system modification is considered to be replacing, repairing, or upgrading seventy-five percent (75%) or more of a vapor collection and control system of a facility.

(b) Pursuant to 326 IAC 8-4-6(k)(6), each vapor leakage and blockage test must, at a minimum, include the following:

(A) A pressure decay or leak test.

(B) A dynamic pressure drop test.

(C) A liquid blockage test.

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.39.4 Record Keeping Requirements

Pursuant to 326 IAC 8-4-6(i), Permittee shall retain copies of all records and reports adequate to clearly demonstrate the following:

(1) That a certified vapor collection and control system has been installed and tested to verify its performance according to its specifications.

(2) That proper maintenance has been conducted in accordance with the manufacturer's specifications and requirements.

(3) The time period and duration of all malfunctions of the vapor collection and control system.

(4) The motor vehicle fuel throughput of the facility for each calendar month of the previous year.

(5) That operators and employees are trained and instructed in the proper operation and maintenance of the vapor collection and control system.

SECTION D.40 FACILITY OPERATION CONDITIONS – CALUMET WAREHOUSE

Facility Description [326 IAC 2-7-5(15)]:

(bb) A warehouse identified as the Calumet Warehouse that includes the following emission sources and may also include other insignificant activities listed in Section A.4 of this permit [326 IAC 6.8-1-2(b)]:

(1) Kewanee Boiler No. 1 with a maximum design capacity of 5.5 MMBtu/hr heat input and is natural gas-fired only, venting to stack, S-1.

(2) Kewanee Boiler No. 2 with a maximum design capacity of 5.5 MMBtu/hr heat input and is natural gas-fired only, venting to stack, S-2.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.40.1 Particulate Matter Limitation (PM) [326 IAC 6.8-1-2(b)]

Pursuant to 326 IAC 6.8-1-2(b)(5), the particulate matter content of natural gas burned in the Kewanee Boilers shall be limited to 0.01 grains per dry standard cubic foot natural gas.

SECTION D.41 **FACILITY OPERATION CONDITIONS - Tank Cleaning Facility**

Facility Description [326 IAC 2-7-5(15)]

One (1) tank sludge cleaning facility (identified as Tank Cleaning Facility) with a maximum throughput of 300 gallons per minute of storage tank sludge/cutter stock mix per hour, with VOC and HAP emissions voluntarily controlled using either an electric catalytic oxidizer (identified as F-1) or a wet scrubber/carbon canister system (identified as S-1). The facility is approved for construction in 2007, is operated as a batch process, and consists of the following emission units:

(a) Four (4) mix tanks identified as Mix Tank #1, #2, #3, and #4. Each tank has maximum capacity of 21,000 gallons, with emissions voluntarily controlled by either the catalytic oxidizer F-1 or the wet scrubber/carbon canister system S-1.

(b) Two (2) enclosed centrifuges (identified as Centrifuge #1 and #2) with no process vents.

(c) One (1) diesel-fired boiler (identified as C-1), with a maximum heat input capacity of 8.4 MMBtu per hour burning low-sulfur (less than 0.05% sulfur by weight) diesel fuel. Emissions are exhausted at stack C-1-01. There is no control device for this emission unit.

(d) One (1) diesel-fired air compressor (identified as J-2), with a maximum heat input capacity of 0.84 MMBtu per hour. This compressor is a 120 hp reciprocating internal combustion engine. Emissions are exhausted through vent J-2. There is no control device for this emission unit.

(e) Two (2) diesel-fired process pumps (identified as J-1 and J-3), each having a maximum heat input capacity of 0.70 MMBtu per hour. These pumps are 100 hp reciprocating internal combustion engines. Emissions from pumps J-1 and J-3 are exhausted through vents J-1 and J-3, respectively. There are no control devices for this emission unit.

(f) Six (6) portable rectangular storage tanks, including:

(1) Two (2) Reclaimed Oil Tanks identified as ROT-1 and ROT-2. Each tank has a maximum storage capacity of 21,000 gallons and is used to store reclaimed sludge and cutter stock. Emissions are voluntarily controlled by either the catalytic oxidizer F-1 or the wet scrubber/carbon canister system S-1.

(2) Three (3) Cutter Stock Tanks identified as CST-1, CST-2, and CST-3. Each tank has a maximum storage capacity of 21,000 gallons and is used to store Cutter Stock. Emissions are voluntarily controlled by either the catalytic oxidizer F-1 or the wet scrubber/carbon canister system S-1.

(3) One (1) Concentrate Tank identified as CT-1. This tank has a maximum storage capacity of 21,000 gallons and is used to store cutter stock and tank sludge mix. Emissions are voluntarily controlled by either the catalytic oxidizer F-1 or the wet scrubber/carbon canister system S-1.

(g) One (1) electric catalytic oxidizer, identified as F-1, a maximum gas flow rate of 400 scfm. Emissions are exhausted at stack F-1-01. Under 40 CFR 60, Subpart J, the catalytic oxidizer is considered a fuel gas combustion device.

(h) Equipment leaks of VOC and HAP from pumps, valves, and connectors. Under 40 CFR 63, Subpart CC, equipment leaks from pumps, valves, and connectors associated with the Tank Cleaning Facility are affected facilities in organic hazardous air pollutant service.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.41.1 Volatile Organic Compounds (VOC) Limits [326 IAC 2-3][326 IAC 2-2]

The Tank Cleaning Facility shall be limited to less than 4,440 hours of operation per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with this limitation renders the requirements of 326 IAC 2-2 and 326 IAC 2-3 not applicable to the installation of the Tank Cleaning Facility, which consists of Mix Tanks #1 through #4; Centrifuges #1 and #2; Boiler C-1; Compressor J-2; Processes Pumps J-1 and J-3; and Storage Tanks ROT-1, ROT-2, CST-1, CST-2, CST-3, and CT-1.

D.41.2 Particulate Matter [326 IAC 6.8-1-2]

(a) Pursuant to 326 IAC 6.8-1-2(b)(2), the particulate matter emissions from the Boiler C-1 shall be limited to 0.15 pounds per million Btu.

(b) Pursuant to 326 IAC 6.8-1-2(a), the particulate matter emissions from the pump engines (J-1 and J-3) and the compressor engine (J-2) shall be each limited to 0.03 grains per dry standard cubic foot.

D.41.3 Storage Tank Requirements [326 IAC 8-9]

Pursuant to 326 IAC 8-9-6 (Volatile Organic Liquid Storage Vessels), the Permittee shall record and submit to IDEM, OAQ a report containing the following information for Reclaimed Oil Tanks ROT-1 and ROT-2; Cutter Stock Tanks CST-1, CST-2, and CST-3; and Concentrate Tank CT-1:

(a) The vessel identification number.

(b) The vessel dimensions.

(c) The vessel capacity.

The Permittee shall keep all records as described in (a) through (c) for the life of the vessel.

D.41.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60, Subpart J, the Permittee shall comply with the requirements specified in Section E.2 for the electric catalytic oxidizer F-1.

D.41.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8][326 IAC 20-16-1][40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, valves and connectors located at the Tank Cleaning Facility.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.41.6 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.41.7 Record Keeping Requirements

(a) To demonstrate compliance with Condition D.41.1, the Permittee shall maintain records of the number of operating hours for the Tank Cleaning Facility.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.41.4, the Permittee shall maintain the records specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.41.5(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.41.5(b), the Permittee shall keep records as specified in Section E.1 and E.4.

D.41.8 Reporting Requirements

(a) A quarterly summary of the information to document compliance with Condition D.41.1 shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.41.4, the Permittee shall submit to IDEM, OAQ the reports specified in Condition E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.41.5(a), the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.41.5(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.

SECTION D.42 FACILITY OPERATION CONDITIONS – Gas Oil Hydrotreating Unit

Facility Description [326 IAC 2-7-5(15)]

(nn) The Gas Oil Hydrotreater (GOHT) Unit, identified as Unit ID 802 and rated at 120,000 barrels per day. The GOHT reduces the sulfur and nitrogen content of the FCU feed and improves the hydrogen content. Operation of the GOHT will enable the FCU to meet gasoline sulfur specifications and to improve FCU conversion yields. The GOHT Unit will be constructed as part of the CXHO Project and includes the following emission units:

(1) Process heaters comprising of:

Heater Identification	Maximum Heat Input Capacity (mmBTU/hr)	Stack Exhausted To	Emissions Controls
F-901A	47	802-01	Ultra low-NOx burners
F-901B	47	802-02	Ultra low-NOx burners

(2) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves, flanges or other connectors, and instrumentation systems.

(3) The GOHT Unit vents to the GOHT Flare (included in Section D.35), used to control VOC emissions during emergency situations, unit startups and shutdowns.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.42.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from each of the stacks 802-01 and 802-02 shall not exceed 0.03 grains per dry standard cubic foot.

D.42.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for the heaters identified as F-901A and F-901B:

(a) The emissions of NOx shall not exceed 0.04 pounds per million BTU.

(b) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(c) The emissions of SO2 shall not exceed 2.3 tons per 12 consecutive month period for each of the heaters F-901A and F-901B, with compliance determined at the end of each month.

(d) The emissions of PM and PM-10 each shall not exceed 0.0019 and 0.0075 pounds per million BTU of fuel burned, respectively.

(e) The emissions of CO shall not exceed 0.02 pounds per million BTU.

(f) The Permittee shall comply with the following fuel usage limits:

Unit ID	Firing rate limit (10^3 mmBTU) per 12 consecutive

	month period
F-901A	411.72
F-901B	411.72

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.42.3 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [40 CFR 60, Subpart VVa][40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 60, Subpart GGGa, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of VOCs and HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems located at GOHT unit, identified as Unit ID 802.

(c) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.42.4 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14][40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ] [326 IAC 12]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.42.5 Fuel Gas Hydrogen Sulfide (H2S) [326 IAC 12][40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for process heaters F-901A and F-901B and the GOHT flare.

Compliance Determination Requirements

D.42.6 Operating Requirement

(a) In order to demonstrate compliance with Condition D.42.3(a), the heaters F-901A and F-901B shall operate using only ultra low-NOx burners.

(b) Compliance with the limits in Condition D.42.2(a), (b), (d) and (e) shall be demonstrated as specified in Condition D.0.3.

D.42.7 Continuous Emissions Monitoring

The Total Reduced Sulfur continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for F-901A and F-901B in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.42.8 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.42.9 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall keep records as specified in the LDAR plan.

(b) In order to demonstrate compliance with Condition D.42.2, the Permittee shall maintain the records of monthly firing rates and SO2 emissions at F-901A and F-901B.

(c) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.42.7, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.42.10 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(b) In order to demonstrate compliance with Condition D.42.2, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions for heaters F-901A and F-901B to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.42.2 and D.42.7, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
    (A) Date of downtime.
    (B) Time of commencement.
    (C) Duration of each downtime.
    (D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.43 FACILITY OPERATION CONDITIONS – New Hydrogen Unit

Facility Description [326 IAC 2-7-5(15)

(oo) The New Hydrogen (New HU) unit, identified as Unit ID 801 commissioned as part of the CXHO Project, produces 99+% pure hydrogen needed for the refinery hydrotreating processes. The New HU produces high purity hydrogen by reacting steam with methane. The reaction is carried out by heating the mixture in a furnace and reacting it in the presence of a catalyst. The New HU heaters HU 1 and HU 2 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New HU heater stacks have continuous emissions monitors (CEMS) for NOx and CO. The New HU includes the following sources of emissions and may include insignificant activities listed in Section A.4 of this permit:

(1) Process heaters comprising:

Heater Identification	Maximum Heat Input Capacity (mmBTU/hr)	Stack Exhausted To	Emissions Controls
HU-1	920	801-01	Low NOX burners and selective catalytic reduction
HU-2	920	801-02	Low NOX burners and selective catalytic reduction

* HU Heaters HU 1 and HU 2 combust both natural gas and PSA offgas with a fuel ratio of no more than 25% natural gas and the remainder PSA offgas.

(2) One cooling tower (HU Cooling Tower) rated at 14,000 gallons per minute recirculation rate controlled by high efficiency drift eliminators.

(3) The new Hydrogen Unit is connected to the HU Flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The HU Flare will be operated with a water seal or nitrogen purge. As such, there will be no purge gas emissions from the HU Flare. The HU Flare exhausts to S/V 801 03.

(4) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves, flanges or other connectors, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.43.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from each of the stacks 801-01 and 801-02 shall not exceed 0.03 grains per dry standard cubic foot.

D.43.2 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3]

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

For each of the two (2) heaters HU-1 and HU-2:

(a) The emissions of NOx from each heater shall not exceed 52.4 tons per 12 consecutive month period, with compliance determined at the end of each month.

(c) The emissions of VOC shall not exceed 0.0034 pounds per million BTU.

(d) The emissions of SO2 from each heater shall not exceed 0.0006 pounds per million BTU.

(e) The emissions of PM and PM-10 each shall not exceed 0.0068 pounds per million BTU.

(f) The emissions of CO shall not exceed 60.4 tons per 12 consecutive month period, with compliance determined at the end of each month.

(g) The Permittee shall comply with the following fuel usage limits:

Unit ID	Natural gas firing rate limit (10^3 mmBTU) per 12 consecutive month period	Total Gas gas firing rate limit (10^3 mmBTU) per 12 consecutive month period
HU-1	2014.8	8059.2
HU-2	2014.8	8059.2

For the HU flare pilot gas:

(h) The emissions of NOx shall not exceed 100 pounds per million cubic feet of fuel burned.

(i) The emissions of VOC shall not exceed 5.5 pounds per million cubic feet of fuel burned.

(j) The emissions of SO2 shall not exceed 0.6 pounds per million cubic feet of fuel burned.

(k) The emissions of PM and PM-10 shall not exceed 1.9 and 7.6 pounds per million cubic feet of fuel burned, respectively.

(l) The pilot gas used at the HU flare shall be limited to 2,233,800 cubic feet per 12 consecutive month period.

For the HU cooling tower:

(m) The average concentration of total dissolved solids (TDS) in the water input to HU Cooling Tower shall not exceed an average annual concentration of 6300 mg/L per 12 consecutive month period.

(n) The emissions of PM and PM-10 from HU Cooling tower shall not exceed 0.42 pounds per hour.

Compliance with the firing rate limits and the NOx, VOC, CO, SO2, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions for NOx, VOC, CO, SO2, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.43.3 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [40 CFR 60, Subpart GGGa] [40 CFR 60, Subpart VVa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Section E.1 for equipment leaks of VOCs and HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems located at GOHT unit, located at HU unit, identified as Unit ID 801.

(c) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.43.4 Fuel Gas Hydrogen Sulfide (H2S) [326 IAC 12][40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for process heaters HU-1 and HU-2.

D.43.5 Standards for Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Section E.1 for the New HU flare relating to the control of process vents.

D.43.6 Equipment Leaks of VOC [326 IAC 12] [40 CFR 60, Subpart GGG]

Pursuant to 40 CFR 60, Subpart GGG, the Permittee shall comply with the control device standards specified in Section E.13 for the New HU flare.

D.43.7 Fuel Gas Hydrogen Sulfide (H2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60, Subpart J, the Permittee shall comply with the applicable requirements specified in Section E.2 for the New HU Flare.

Compliance Determination Requirements

D.43.8 Operating Requirement

(a) In order to demonstrate compliance with Condition D.43.2, the Permittee shall operate the heaters HU-1 and HU-2 using only low-NOx burners.
(b) In order to comply with Condition D.43.2, the SCRs shall be operated as necessary to meet the NOx emissions limits for heaters HU-1 and HU-2.
(c) In order to comply with Condition D.43.2, the liquid drift eliminator shall be in operation and control PM and PM-10 emissions from the HU Cooling Tower at all times that HU Cooling Tower is in operation.
(d) Compliance with the limits in Condition D.43.2 shall be demonstrated as specified in Condition D.0.3.

D.43.9 Continuous Emissions Monitoring

The CO and NOx continuous emission monitoring systems (CEMS) for HU-1 and HU-2 shall be calibrated, maintained, and operated for determining compliance with CO and NOx emissions limits for HU-1 and HU-2 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.43.10 Compliance Monitoring Requirements [326 IAC 2-3]

To monitor compliance with Condition D.43.2 the Permittee shall take weekly measurements of the total dissolved solids (TDS) in the water input to HU Cooling Tower. If the TDS limitation is exceeded, the Permittee shall perform quantitative water analyses and shall take the remedial action necessary to correct the problem.

D.43.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

D.43.12 Continuous Monitoring – HU Flare [326 IAC 2-2]

The Total Reduced Sulfur continuous emission monitoring systems (CEMS) for the HU Flare shall be calibrated, maintained, and operated in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. For purposes of demonstrating compliance with Condition D.0.1, the SO2 emissions from the HU Flare shall be calculated as provided in Paragraph (g) of Condition D.0.1 based on the conversion of one mole of sulfur in the gas to one mole of S.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.43.13 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall keep records as specified in the LDAR plan.

(b) In order to demonstrate compliance with Condition D.43.2, the Permittee shall maintain the records of monthly firing rates using natural gas and PSA tailgas and CO, NOx and SO2 emissions at HU-1 and HU-2.

(c) In order to demonstrate compliance with Condition D.43.2, the Permittee shall maintain the records of monthly firing rates using pilot gas at the HU flare.

(d) To document compliance with Condition D.43.2, the Permittee shall maintain records of the total dissolved solids (TDS) in the water input to HU Cooling Tower and any remedial actions taken (including the date remedial actions were initiated).

(e) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.43.9, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.43.14 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(b) In order to demonstrate compliance with Condition D.43.2, the Permittee shall submit a quarterly summary of the fuel usages at heaters HU-1, HU-2 and HU flare and CO, NOx, and SO2 emissions for HU-1 and HU-2 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.43.2 and D.43.9, the Permittee shall submit reports of excess SO2, CO, and NOx emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
    (A) Date of downtime.
    (B) Time of commencement.
    (C) Duration of each downtime.
    (D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.44 FACILITY OPERATION CONDITIONS – New Boilers

Facility Description [326 IAC 2-7-5(15)]

(oo) Two (2) new boilers, identified as New Boiler 1 and New Boiler 2, per SPM 089-25488-00453, each rated at 580 million BTU per hour, equipped with low-NOx burners and/or Selective Catalytic Reduction (SCR) for control of NOx, using either blended natural gas and refinery gas or only refinery fuel gas. A separate TRS CEMS shall be installed to measure the sulfur content of the fuel gas or fuel gas-natural gas blend fed to New Boiler 1 and New Boiler 2.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.44.1 Particulate Matter Emissions - Lake County [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2(b)(3), the particulate matter emissions from New Boiler 1 and New Boiler 2 shall be no greater than one-hundredth (0.01) grain per dry standard cubic foot (dscf).

D.44.2 SO2 Emissions Limitation

The SO2 emissions from each of the boilers identified as New Boiler 1 and New Boiler 2 hall be limited to less than 25 tons per 12 consecutive month period.

Compliance with this limit shall render the requirements of 326 IAC 7-4.1-1 (Lake County SO2 Emissions Limitations) not applicable.

D.44.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) The firing rate (total) at New Boiler 1 and New Boiler 2 shall not exceed 9,907,560 mmBTU per 12 consecutive month period, with compliance determined at the end of each month.

(b) The emissions of NOx (total) from the boilers shall not exceed 322.0 tons per 12 consecutive month period, with compliance determined at the end of each month.

(c) The emissions of SO2 from each of the boilers shall not exceed 24.9 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) The emissions of CO (total) shall not exceed 118.9 tons per 12 consecutive month period, with compliance determined at the end of each month.

(e) The emissions of PM and PM-10 each shall not exceed 0.0019 and 0.0075 pounds per million BTU, respectively.

(f) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

Compliance with the firing rate limits and the NOx, VOC, CO, SO2, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions for NOx, VOC, CO, SO2, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.44.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for New Boiler 1 and New Boiler 2.

D.44.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.44.6 Wastewater / Waste Streams [40 CFR 60, Subpart QQQ][326 IAC 12]

Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

D.44.7 Standards of Performance for Boilers [40 CFR Part 60, Subpart Db] [326 IAC 12]

Pursuant to 40 CFR 60, Subpart Db, the Permitee shall comply with the requirements of Section E.22 for the New Boiler 1 and New Boiler 2.

Compliance Determination Requirements

D.44.8 Operating Requirement

(1) In order to demonstrate compliance with D.44.3, fuel oil shall not be used as fuel for New Boiler 1 and New Boiler 2.

(2) Compliance with the limits in Condition D.44.3(e) and (f) shall be demonstrated as specified in Condition D.0.3.

D.44.9 Continuous Emissions Monitoring

The Total Reduced Sulfur, CO and NOx continuous emission monitoring systems (CEMS) for New Boiler 1 and New Boiler 2 shall be calibrated, maintained, and operated for determining compliance with SO2, CO and NOx emissions limits for New Boiler 1 and New Boiler 2 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

D.44.10 Requirement to Submit a Significant Permit Modification Application [326 IAC 2-7-12] [326 IAC 2-7-5]

In the event that New Boiler 1 and New Boiler 2 are constructed prior to 2009, the NOx authorized account representative shall submit an application for a significant permit modification to IDEM, OAQ requesting the incorporation of NOx Budget Permit requirements for New Boiler 1 and New Boiler 2 under 326 IAC 10-4 into the Title V permit.

(a) The significant permit modification application shall be consistent with 326 IAC 2-7-12, including information sufficient for IDEM, OAQ to incorporate into the Title V permit the applicable requirements of 326 IAC 10-4, a description of the affected source and activities subject to the requirements, and a description of how the Permittee will meet the applicable requirements.

(b) For any source, with one (1) or more NO_x budget units that commences operation on or after January 1, 2001, the NO_x authorized account representative shall submit a complete NO_x budget permit application covering each NO_x budget unit at least two hundred seventy (270) days before the date on which the NO_x budget unit commences operation.

(c) The significant permit modification application shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53, IGCN 1003
Indianapolis, Indiana 46204-2251

Compliance Monitoring Requirements

D.44.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.44.12 Record Keeping Requirements

(a) In order to document compliance with Conditions D.44.3 and D.44.7, the Permittee shall maintain a daily record of the following for New Boiler 1 and New Boiler 2:

(1) operational status of each facility,

(2) fuel type,

(3) average daily sulfur content for each fuel type,

(4) average daily fuel gravity for each fuel type,

(5) total daily fuel usage for each type, and

(6) heat content of each fuel type.

(c) Pursuant to 40 CFR 60, Subpart J, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.44.5, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall keep records as specified in Sections E.1 and E.4.

(f) Pursuant to 40 CFR 60, Subpart Db, the Permittee shall keep records as specified in Section E.22.

(h) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall keep records as specified in Section E.6.

(i) In order to demonstrate compliance with Condition D.44.3, the Permittee shall maintain the records of monthly firing rates and CO, NOx, and SO2 emissions at New Boiler 1 and New Boiler 2.

(j) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.44.10, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.44.13 Reporting Requirements

(a) Pursuant to 40 CFR 60, Subpart J, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(b) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.44.5, the Permittee shall submit reports as specified in the LDAR plan.

(c) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall submit reports as specified in Sections E.1 and E.4.

(d) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall submit reports as specified in Section E.6.

(e) Pursuant to 40 CFR 60, Subpart Db, the Permittee shall submit reports as specified in Section E.22.

(f) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.44.3 and D.44.9, the Permittee shall submit reports of excess SO2, NOx and CO emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
    (A) Date of downtime.
    (B) Time of commencement.
    (C) Duration of each downtime.
    (D) Reasons for each downtime.
    (E) Nature of system repairs and adjustments

SECTION D.45 FACILITY OPERATION CONDITIONS – Firepump Engines and Concrete Crusher

Facility Description [326 IAC 2-7-5(15)]

Insignificant Activity:

(ff) Three (3) emergency firepump engines, identified as Firepump 1, 2 and 3, per SPM 089-25488-00453, each rated at 390 HP.

(gg) One (1) concrete crushing process, per SPM 089-25488-00453, with a maximum processing capacity of 120 tons per hour, having two (2) transfer points.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.45.1 Particulate Matter Emissions - Lake County [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2(a), the particulate matter emissions from Firepump 1, Firepump 2, Firepump 3 and the concrete crushing operation shall not exceed 0.03 gr/dscf.

D.45.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) The hours of operation for each of the three firepump engines shall not exceed 500 hours per year.

(b) The total amount of concrete processed by the concrete crusher shall not exceed 18,000 tons.

Compliance with the emissions limits at the three firepumps and the other units at this source, shall ensure that the net emissions increases, including fugitive emissions for NOx, VOC, CO, SO2, PM and PM-10 for the CXHO project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.45.3 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60, Subpart IIII] [326 IAC 12]

Pursuant to 40 CFR 60, Subpart IIII, the Permitee shall comply with the requirements of Section E.23 for emergency generators and emergency fire pumps.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.45.4 Record Keeping Requirements

Pursuant to 40 CFR 60, Subpart IIII, the Permittee shall keep records as specified in Section E.23.

D.45.5 Reporting Requirements

Pursuant to 40 CFR 60, Subpart IIII, the Permittee shall submit reports as specified in Section E.23.

SECTION E.1 40 CFR Part 63, Subpart CC – National Emission Standards for Hazardous Air Pollutants For Petroleum Refineries

E.1.1 General Provisions Relating to NESHAP Subpart CC [40 CFR Part 63, Subpart CC] [326 IAC 20-1]

Pursuant to 40 CFR 63.640, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, as specified in Table 6 of 40 CFR Part 63, Subpart CC in accordance with the schedule in 40 CFR Part 63, Subpart CC.

E.1.2 NESHAP Subpart CC Requirements [40 CFR Part 63, Subpart CC] [326 IAC 20-16]

Pursuant to 40 CFR 63.640, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart CC, which are incorporated by reference in 326 IAC 20-16, for all affected storage tanks, process vents, wastewater streams and wastewater treatment operations, equipment leaks, gasoline loading racks, and marine vessel loading operations:

§63.640 Applicability and designation of affected source.

(a) This subpart applies to petroleum refining process units and to related emission points that are specified in paragraphs (c)(5) through (c)(7) of this section that are located at a plant site that meet the criteria in paragraphs (a)(1) and (a)(2) of this section;

(1) Are located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act; and

(2) Emit or have equipment containing or contacting one or more of the hazardous air pollutants listed in table 1 of this subpart.

(c) For the purpose of this subpart, the affected source shall comprise all emission points, in combination, listed in paragraphs (c)(1) through (c)(7) of this section that are located at a single refinery plant site.

(1) All miscellaneous process vents from petroleum refining process units meeting the criteria in paragraph (a) of this section;

(2) All storage vessels associated with petroleum refining process units meeting the criteria in paragraph (a) of this section;

(3) All wastewater streams and treatment operations associated with petroleum refining process units meeting the criteria in paragraph (a) of this section;

(4) All equipment leaks from petroleum refining process units meeting the criteria in paragraph (a) of this section;

(5) All gasoline loading racks classified under Standard Industrial Classification code 2911 meeting the criteria in paragraph (a) of this section;

(6) All marine vessel loading operations located at a petroleum refinery meeting the criteria in paragraph (a) of this section and the applicability criteria of subpart Y, §63.560; and

(7) All storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery meeting the criteria in paragraph (a) of this section.

(d) The affected source subject to this subpart does not include the emission points listed in paragraphs (d)(1) through (d)(5) of this section.

(1) Stormwater from segregated stormwater sewers;

(2) Spills;

(3) Any pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system that is intended to operate in organic hazardous air pollutant service, as defined in §63.641 of this subpart, for less than 300 hours during the calendar year;

(4) Catalytic cracking unit and catalytic reformer catalyst regeneration vents, and sulfur plant vents; and

(5) Emission points routed to a fuel gas system, as defined in §63.641 of this subpart. No testing, monitoring, recordkeeping, or reporting is required for refinery fuel gas systems or emission points routed to refinery fuel gas systems.

(e) The owner or operator shall follow the procedures specified in paragraphs (e)(1) and (e)(2) of this section to determine whether a storage vessel is part of a source to which this subpart applies.

(1) Where a storage vessel is used exclusively by a process unit, the storage vessel shall be considered part of that process unit.

(i) If the process unit is a petroleum refining process unit subject to this subpart, then the storage vessel is part of the affected source to which this subpart applies.

(ii) If the process unit is not subject to this subpart, then the storage vessel is not part of the affected source to which this subpart applies.

(2) If a storage vessel is not dedicated to a single process unit, then the applicability of this subpart shall be determined according to the provisions in paragraphs (e)(2)(i) through (e)(2)(iii) of this section.

(i) If a storage vessel is shared among process units and one of the process units has the predominant use, as determined by paragraphs (e)(2)(i)(A) and (e)(2)(i)(B) of this section, then the storage vessel is part of that process unit.

(A) If the greatest input on a volume basis into the storage vessel is from a process unit that is located on the same plant site, then that process unit has the predominant use.

(B) If the greatest input on a volume basis into the storage vessel is provided from a process unit that is not located on the same plant site, then the predominant use shall be the process unit that receives the greatest amount of material on a volume basis from the storage vessel at the same plant site.

(ii) If a storage vessel is shared among process units so that there is no single predominant use, and at least one of those process units is a petroleum refining process unit subject to this subpart, the storage vessel shall be considered to be part of the petroleum refining process unit that is subject to this subpart. If more than one petroleum refining process unit is subject to this subpart, the owner or operator may assign the storage vessel to any of the petroleum refining process units subject to this subpart.

(iii) If the predominant use of a storage vessel varies from year to year, then the applicability of this subpart shall be determined based on the utilization of that storage vessel during the year preceding promulgation of this subpart. This determination shall be reported as specified in §63.654(h)(6)(ii) of this subpart.

(f) The owner or operator shall follow the procedures specified in paragraphs (f)(1) through (f)(5) of this section to determine whether a miscellaneous process vent from a distillation unit is part of a source to which this subpart applies.

(1) If the greatest input to the distillation unit is from a process unit located on the same plant site, then the distillation unit shall be assigned to that process unit.

(2) If the greatest input to the distillation unit is provided from a process unit that is not located on the same plant site, then the distillation unit shall be assigned to the process unit located at the same plant site that receives the greatest amount of material from the distillation unit.

(3) If a distillation unit is shared among process units so that there is no single predominant use, as described in paragraphs (f)(1) and (f)(2) of this section, and at least one of those process units is a petroleum refining process unit subject to this subpart, the distillation unit shall be assigned to the petroleum refining process unit that is subject to this subpart. If more than one petroleum refining process unit is subject to this subpart, the owner or operator may assign the distillation unit to any of the petroleum refining process units subject to this rule.

(4) If the process unit to which the distillation unit is assigned is a petroleum refining process unit subject to this subpart and the vent stream contains greater than 20 parts per million by volume total organic hazardous air pollutants, then the vent from the distillation unit is considered a miscellaneous process vent (as defined in §63.641 of this subpart) and is part of the source to which this subpart applies.

(5) If the predominant use of a distillation unit varies from year to year, then the applicability of this subpart shall be determined based on the utilization of that distillation unit during the year preceding promulgation of this subpart. This determination shall be reported as specified in §63.654(h)(6)(iii).

(g) The provisions of this subpart do not apply to the processes specified in paragraphs (g)(1) through (g)(7) of this section.

(1) Research and development facilities, regardless of whether the facilities are located at the same plant site as a petroleum refining process unit that is subject to the provisions of this subpart;

(2) Equipment that does not contain any of the hazardous air pollutants listed in table 1 of this subpart that is located within a petroleum refining process unit that is subject to this subpart;

(3) Units processing natural gas liquids;

(4) Units that are used specifically for recycling discarded oil;

(5) Shale oil extraction units;

(6) Ethylene processes; and

(7) Process units and emission points subject to subparts F, G, H, and I of this part.

(h) Except as provided in paragraphs (k), (l), or (m) of this section, sources subject to this subpart are required to achieve compliance on or before the dates specified in paragraphs (h)(1) through (h)(4) of this section.

(1) New sources that commence construction or reconstruction after July 14, 1994 shall be in compliance with this subpart upon initial startup or the date of promulgation of this subpart, whichever is later, as provided in §63.6(b) of subpart A of this part.

(2) Except as provided in paragraphs (h)(3) through (h)(5) of this section, existing sources shall be in compliance with this subpart no later than August 18, 1998, except as provided in §63.6(c) of subpart A of this part, or unless an extension has been granted by the Administrator as provided in §63.6(i) of subpart A of this part.

(3) Marine tank vessels at existing sources shall be in compliance with this subpart no later than August 18, 1999 unless the vessels are included in an emissions average to generate emission credits. Marine tank vessels used to generate credits in an emissions average shall be in compliance with this subpart no later than August 18, 1998 unless an extension has been granted by the Administrator as provided in §63.6(i).

(4) Existing Group 1 floating roof storage vessels shall be in compliance with §63.646 at the first degassing and cleaning activity after August 18, 1998, or within 10 years after promulgation of the rule, whichever is first.

(5) An owner or operator may elect to comply with the provisions of §63.648 (c) through (i) as an alternative to the provisions of §63.648 (a) and (b). In such cases, the owner or operator shall comply no later than the dates specified in paragraphs (h)(5)(i) through (h)(5)(iii) of this section.

(i) Phase I (see table 2 of this subpart), beginning on August 18, 1998;

(ii) Phase II (see table 2 of this subpart), beginning no later than August 18, 1999; and

(iii) Phase III (see table 2 of this subpart), beginning no later than February 18, 2001.

(i) If an additional petroleum refining process unit is added to a plant site that is a major source as defined in section 112(a) of the Clean Air Act, the addition shall be subject to the requirements for a new source if it meets the criteria specified in paragraphs (i)(1) through (i)(3) of this section:

(1) It is an addition that meets the definition of construction in §63.2 of subpart A of this part;

(2) Such construction commenced after July 14, 1994; and

(3) The addition has the potential to emit 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.

(j) If any change is made to a petroleum refining process unit subject to this subpart, the change shall be subject to the requirements for a new source if it meets the criteria specified in paragraphs (j)(1) and (j)(2) of this section:

(1) It is a change that meets the definition of reconstruction in §63.2 of subpart A of this part; and

(2) Such reconstruction commenced after July 14, 1994.

(k) If an additional petroleum refining process unit is added to a plant site or a change is made to a petroleum refining process unit and the addition or change is determined to be subject to the new source requirements according to paragraphs (i) or (j) of this section it must comply with the requirements specified in paragraphs (k)(1) and (k)(2) of this section:

(1) The reconstructed source, addition, or change shall be in compliance with the new source requirements upon initial startup of the reconstructed source or by the date of promulgation of this subpart, whichever is later; and

(2) The owner or operator of the reconstructed source, addition, or change shall comply with the reporting and recordkeeping requirements that are applicable to new sources. The applicable reports include, but are not limited to:

(i) The application for approval of construction or reconstruction shall be submitted as soon as practical before the construction or reconstruction is planned to commence (but it need not be sooner than 90 days after the date of promulgation of this subpart);

(ii) The Notification of Compliance Status report as required by §63.654(f) for a new source, addition, or change;

(iii) Periodic Reports and Other Reports as required by §63.654 (g) and (h);

(iv) Reports and notifications required by §60.487 of subpart VV of part 60 or §63.182 of subpart H of this part. The requirements for subpart H are summarized in table 3 of this subpart;

(v) Reports required by 40 CFR 61.357 of subpart FF;

(vi) Reports and notifications required by §63.428 (b), (c), (g)(1), and (h)(1) through (h)(3) of subpart R. These requirements are summarized in table 4 of this subpart; and

(vii) Reports and notifications required by §§63.565 and 63.567 of subpart Y of this part. These requirements are summarized in table 5 of this subpart.

(l) If an additional petroleum refining process unit is added to a plant site or if a miscellaneous process vent, storage vessel, gasoline loading rack, or marine tank vessel loading operation that meets the criteria in paragraphs (c)(1) through (c)(7) of this section is added to an existing petroleum refinery or if another deliberate operational process change creating an additional Group 1 emission point(s) (as defined in §63.641) is made to an existing petroleum refining process unit, and if the addition or process change is not subject to the new source requirements as determined according to paragraphs (i) or (j) of this section, the requirements in paragraphs (l)(1) through (l)(3) of this section shall apply. Examples of process changes include, but are not limited to, changes in production capacity, or feed or raw material where the change requires construction or physical alteration of the existing equipment or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph and paragraph (m) of this section, process changes do not include: Process upsets, unintentional temporary process changes, and changes that are within the equipment configuration and operating conditions documented in the Notification of Compliance Status report required by §63.654(f).

(1) The added emission point(s) and any emission point(s) within the added or changed petroleum refining process unit are subject to the requirements for an existing source.

(2) The added emission point(s) and any emission point(s) within the added or changed petroleum refining process unit shall be in compliance with this subpart by the dates specified in paragraphs (l)(2)(i) or (l)(2)(ii) of this section, as applicable.

(i) If a petroleum refining process unit is added to a plant site or an emission point(s) is added to any existing petroleum refining process unit, the added emission point(s) shall be in compliance upon initial startup of any added petroleum refining process unit or emission point(s) or by 3 years after the date of promulgation of this subpart, whichever is later.

(ii) If a deliberate operational process change to an existing petroleum refining process unit causes a Group 2 emission point to become a Group 1 emission point (as defined in §63.641), the owner or operator shall be in compliance upon initial startup or by 3 years after the date of promulgation of this subpart, whichever is later, unless the owner or operator demonstrates to the Administrator that achieving compliance will take longer than making the change. If this demonstration is made to the Administrator's satisfaction, the owner or operator shall follow the procedures in paragraphs (m)(1) through (m)(3) of this section to establish a compliance date.

(3) The owner or operator of a petroleum refining process unit or of a storage vessel, miscellaneous process vent, wastewater stream, gasoline loading rack, or marine tank vessel loading operation meeting the criteria in paragraphs (c)(1) through (c)(7) of this section that is added to a plant site and is subject to the requirements for existing sources shall comply with the reporting and recordkeeping requirements that are applicable to existing sources including, but not limited to, the reports listed in paragraphs (l)(3)(i) through (l)(3)(vii) of this section. A process change to an existing petroleum refining process unit shall be subject to the reporting requirements for existing sources including, but not limited to, the reports listed in paragraphs (l)(3)(i) through (l)(3)(vii) of this section. The applicable reports include, but are not limited to:

(i) The Notification of Compliance Status report as required by §63.654(f) for the emission points that were added or changed;

(ii) Periodic Reports and other reports as required by §63.654 (g) and (h);

(iii) Reports and notifications required by sections of subpart A of this part that are applicable to this subpart, as identified in table 6 of this subpart.

(iv) Reports and notifications required by §63.182, or 40 CFR 60.487. The requirements of subpart H of this part are summarized in table 3 of this subpart;

(v) Reports required by §61.357 of subpart FF;

(vi) Reports and notifications required by §63.428 (b), (c), (g)(1), and (h)(1) through (h)(3) of subpart R of this part. These requirements are summarized in table 4 of this subpart; and

(vii) Reports and notifications required by §63.567 of subpart Y of this part. These requirements are summarized in table 5 of this subpart.

(4) If pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, or instrumentation systems are added to an existing source, they are subject to the equipment leak standards for existing sources in §63.648. A notification of compliance status report shall not be required for such added equipment.

(m) If a change that does not meet the criteria in paragraph (l) of this section is made to a petroleum refining process unit subject to this subpart, and the change causes a Group 2 emission point to become a Group 1 emission point (as defined in §63.641), then the owner or operator shall comply with the requirements of this subpart for existing sources for the Group 1 emission point as expeditiously as practicable, but in no event later than 3 years after the emission point becomes Group 1.

(1) The owner or operator shall submit to the Administrator for approval a compliance schedule, along with a justification for the schedule.

(2) The compliance schedule shall be submitted within 180 days after the change is made, unless the compliance schedule has been previously submitted to the permitting authority. If it is not possible to determine until after the change is implemented whether the emission point has become Group 1, the compliance schedule shall be submitted within 180 days of the date when the affect of the change is known to the source. The compliance schedule may be submitted in the next Periodic Report if the change is made after the date the Notification of Compliance Status report is due.

(3) The Administrator shall approve or deny the compliance schedule or request changes within 120 calendar days of receipt of the compliance schedule and justification. Approval is automatic if not received from the Administrator within 120 calendar days of receipt.

(n) Overlap of subpart CC with other regulations for storage vessels.

(1) After the compliance dates specified in paragraph (h) of this section, a Group 1 or Group 2 storage vessel that is part of an existing source and is also subject to the provisions of 40 CFR part 60, subpart Kb, is required to comply only with the requirements of 40 CFR part 60, subpart Kb, except as provided in paragraph (n)(8) of this section.

(2) After the compliance dates specified in paragraph (h) of this section a Group 1 storage vessel that is part of a new source and is subject to 40 CFR part 60, subpart Kb is required to comply only with this subpart.

(3) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is part of a new source and is subject to the control requirements in §60.112b of 40 CFR part 60, subpart Kb is required to comply only with 40 CFR part 60, subpart Kb except as provided in paragraph (n)(8) of this section.

(4) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is part of a new source and is subject to 40 CFR 60.110b, but is not required to apply controls by 40 CFR 60.110b or 60.112b is required to comply only with this subpart.

(5) After the compliance dates specified in paragraph (h) of this section a Group 1 storage vessel that is also subject to the provisions of 40 CFR part 60, subparts K or Ka is required to only comply with the provisions of this subpart.

(6) After compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to the control requirements of 40 CFR part 60, subparts K or Ka is required to comply only with the provisions of 40 CFR part 60, subparts K or Ka except as provided for in paragraph (n)(9) of this section.

(7) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to 40 CFR part 60, subparts K or Ka, but not to the control requirements of 40 CFR part 60, subparts K or Ka, is required to comply only with this subpart.

(8) Storage vessels described by paragraphs (n)(1) and (n)(3) of this section are to comply with 40 CFR part 60, subpart Kb except as provided for in paragraphs (n)(8)(i) through (n)(8)(vi) of this section.

(i) Storage vessels that are to comply with §60.112b(a)(2) of subpart Kb are exempt from the secondary seal requirements of §60.112b(a)(2)(i)(B) during the gap measurements for the primary seal required by §60.113b(b) of subpart Kb.

(ii) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in §60.113b(b) of subpart Kb or to inspect the vessel to determine compliance with §60.113b(a) of subpart Kb because the roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or §63.120(b)(7)(ii) of subpart G.

(iii) If a failure is detected during the inspections required by §60.113b(a)(2) or during the seal gap measurements required by §60.113b(b)(1), and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to two extensions of up to 30 additional calendar days each. The owner or operator is not required to provide a request for the extension to the Administrator.

(iv) If an extension is utilized in accordance with paragraph (n)(8)(iii) of this section, the owner or operator shall, in the next periodic report, identify the vessel, provide the information listed in §60.113b(a)(2) or §60.113b(b)(4)(iii), and describe the nature and date of the repair made or provide the date the storage vessel was emptied.

(v) Owners and operators of storage vessels complying with subpart Kb of part 60 may submit the inspection reports required by §§60.115b(a)(3), (a)(4), and (b)(4) of subpart Kb as part of the periodic reports required by this subpart, rather than within the 30-day period specified in §§60.115b(a)(3), (a)(4), and (b)(4) of subpart Kb.

(vi) The reports of rim seal inspections specified in §60.115b(b)(2) are not required if none of the measured gaps or calculated gap areas exceed the limitations specified in §60.113b(b)(4). Documentation of the inspections shall be recorded as specified in §60.115b(b)(3).

(9) Storage vessels described by paragraph (n)(6) of this section that are to comply with 40 CFR part 60, subpart Ka, are to comply with only subpart Ka except as provided for in paragraphs (n)(9)(i) through (n)(9)(iv) of this section.

(i) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in §60.113a(a)(1) of subpart Ka because the floating roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or §63.120(b)(7)(ii) of subpart G.

(ii) If a failure is detected during the seal gap measurements required by §60.113a(a)(1) of subpart Ka, and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to 2 extensions of up to 30 additional calendar days each.

(iii) If an extension is utilized in accordance with paragraph (n)(9)(ii) of this section, the owner or operator shall, in the next periodic report, identify the vessel, describe the nature and date of the repair made or provide the date the storage vessel was emptied. The owner or operator shall also provide documentation of the decision to utilize an extension including a description of the failure, documentation that alternate storage capacity is unavailable, and a schedule of actions that will ensure that the control equipment will be repaired or the vessel emptied as soon as possible.

(iv) Owners and operators of storage vessels complying with subpart Ka of part 60 may submit the inspection reports required by §60.113a(a)(1)(i)(E) of subpart Ka as part of the periodic reports required by this subpart, rather than within the 60-day period specified in §60.113a(a)(1)(i)(E) of subpart Ka.

(o) Overlap of this subpart CC with other regulations for wastewater.

(1) After the compliance dates specified in paragraph (h) of this section a Group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of 40 CFR part 60, subpart QQQ is required to comply only with this subpart.

(p) Overlap of subpart CC with other regulations for equipment leaks. After the compliance dates specified in paragraph (h) of this section equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 are required to comply only with the provisions specified in this subpart.

(q) For overlap of subpart CC with local or State regulations, the permitting authority for the affected source may allow consolidation of the monitoring, recordkeeping, and reporting requirements under this subpart with the monitoring, recordkeeping, and reporting requirements under other applicable requirements in 40 CFR parts 60, 61, or 63, and in any 40 CFR part 52 approved State implementation plan provided the implementation plan allows for approval of alternative monitoring, reporting, or recordkeeping requirements and provided that the permit contains an equivalent degree of compliance and control.

(r) Overlap of subpart CC with other regulations for gasoline loading racks. After the compliance dates specified in paragraph (h) of this section, a Group 1 gasoline loading rack that is part of a source subject to subpart CC and also is subject to the provisions of 40 CFR part 60, subpart XX is required to comply only with this subpart.

§ 63.641 Definitions.

All terms used in this subpart shall have the meaning given them in the Clean Air Act, subpart A of this part, and in this section. If the same term is defined in subpart A and in this section, it shall have the meaning given in this section for purposes of this subpart.

Affected source means the collection of emission points to which this subpart applies as determined by the criteria in §63.640.

Aliphatic means open-chained structure consisting of paraffin, olefin and acetylene hydrocarbons and derivatives.

Annual average true vapor pressure means the equilibrium partial pressure exerted by the stored liquid at the temperature equal to the annual average of the liquid storage temperature for liquids stored above or below the ambient temperature or at the local annual average temperature reported by the National Weather Service for liquids stored at the ambient temperature, as determined:

(1) In accordance with methods specified in §63.111 of subpart G of this part;

(2) From standard reference texts; or

(3) By any other method approved by the Administrator.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

By compound means by individual stream components, not by carbon equivalents.

Car-seal means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Closed vent system means a system that is not open to the atmosphere and is configured of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission point to a control device or back into the process. If gas or vapor from regulated equipment is routed to a process (e.g., to a petroleum refinery fuel gas system), the process shall not be considered a closed vent system and is not subject to closed vent system standards.

Combustion device means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the combustion of organic hazardous air pollutant vapors.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation. For the purpose of reporting and recordkeeping, connector means joined fittings that are accessible.

Continuous record means documentation, either in hard copy or computer readable form, of data values measured at least once every hour and recorded at the frequency specified in §63.654(i).

Continuous recorder means a data recording device recording an instantaneous data value or an average data value at least once every hour.

Control device means any equipment used for recovering, removing, or oxidizing organic hazardous air pollutants. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters. For miscellaneous process vents (as defined in this section), recovery devices (as defined in this section) are not considered control devices.

Delayed coker vent means a vent that is typically intermittent in nature, and usually occurs only during the initiation of the depressuring cycle of the decoking operation when vapor from the coke drums cannot be sent to the fractionator column for product recovery, but instead is routed to the atmosphere through a closed blowdown system or directly to the atmosphere in an open blowdown system. The emissions from the decoking phases of delayed coker operations, which include coke drum deheading, draining, or decoking (coke cutting), are not considered to be delayed coker vents.

Distillate receiver means overhead receivers, overhead accumulators, reflux drums, and condenser(s) including ejector-condenser(s) associated with a distillation unit.

Distillation unit means a device or vessel in which one or more feed streams are separated into two or more exit streams, each exit stream having component concentrations different from those in the feed stream(s). The separation is achieved by the redistribution of the components between the liquid and the vapor phases by vaporization and condensation as they approach equilibrium within the distillation unit. Distillation unit includes the distillate receiver, reboiler, and any associated vacuum pump or steam jet.

Emission point means an individual miscellaneous process vent, storage vessel, wastewater stream, or equipment leak associated with a petroleum refining process unit; an individual storage vessel or equipment leak associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial Classification code 2911; a gasoline loading rack classified under Standard Industrial Classification code 2911; or a marine tank vessel loading operation located at a petroleum refinery.

Equipment leak means emissions of organic hazardous air pollutants from a pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system “in organic hazardous air pollutant service” as defined in this section. Vents from wastewater collection and conveyance systems (including, but not limited to wastewater drains, sewer vents, and sump drains), tank mixers, and sample valves on storage tanks are not equipment leaks.

Flame zone means the portion of a combustion chamber of a boiler or process heater occupied by the flame envelope created by the primary fuel.

Flexible operation unit means a process unit that manufactures different products periodically by alternating raw materials or operating conditions. These units are also referred to as campaign plants or blocked operations.

Flow indicator means a device that indicates whether gas is flowing, or whether the valve position would allow gas to flow, in a line.

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by refinery operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric. The gaseous streams can contain a mixture of methane, light hydrocarbons, hydrogen and other miscellaneous species.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater that is used as a fuel for internal combustion engines.

Gasoline loading rack means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill gasoline cargo tanks.

Group 1 gasoline loading rack means any gasoline loading rack classified under Standard Industrial Classification code 2911 that is located within a bulk gasoline terminal that has a gasoline throughput greater than 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput for the terminal as may be limited by compliance with enforceable conditions under Federal, State, or local law and discovered by the Administrator and any other person.

Group 1 marine tank vessel means a vessel at an existing source loaded at any land- or sea-based terminal or structure that loads liquid commodities with vapor pressures greater than or equal to 10.3 kilopascals in bulk onto marine tank vessels, that emits greater than 9.1 megagrams of any individual HAP or 22.7 megagrams of any combination of HAP annually after August 18, 1999, or a vessel at a new source loaded at any land- or sea-based terminal or structure that loads liquid commodities with vapor pressures greater than or equal to 10.3 kilopascals onto marine tank vessels.

Group 1 miscellaneous process vent means a miscellaneous process vent for which the total organic HAP concentration is greater than or equal to 20 parts per million by volume, and the total volatile organic compound emissions are greater than or equal to 33 kilograms per day for existing sources and 6.8 kilograms per day for new sources at the outlet of the final recovery device (if any) and prior to any control device and prior to discharge to the atmosphere.

Group 1 storage vessel means a storage vessel at an existing source that has a design capacity greater than or equal to 177 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 10.4 kilopascals and stored-liquid annual average true vapor pressure greater than or equal to 8.3 kilopascals and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP; a storage vessel at a new source that has a design storage capacity greater than or equal to 151 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 3.4 kilopascals and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP; or a storage vessel at a new source that has a design storage capacity greater than or equal to 76 cubic meters and less than 151 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 77 kilopascals and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP.

Group 1 wastewater stream means a wastewater stream at a petroleum refinery with a total annual benzene loading of 10 megagrams per year or greater as calculated according to the procedures in 40 CFR 61.342 of subpart FF of part 61 that has a flow rate of 0.02 liters per minute or greater, a benzene concentration of 10 parts per million by weight or greater, and is not exempt from control requirements under the provisions of 40 CFR part 61, subpart FF.

Group 2 gasoline loading rack means a gasoline loading rack classified under Standard Industrial Classification code 2911 that does not meet the definition of a Group 1 gasoline loading rack.

Group 2 marine tank vessel means a marine tank vessel that does not meet the definition of a Group 1 marine tank vessel.

Group 2 miscellaneous process vent means a miscellaneous process vent that does not meet the definition of a Group 1 miscellaneous process vent.

Group 2 storage vessel means a storage vessel that does not meet the definition of a Group 1 storage vessel.

Group 2 wastewater stream means a wastewater stream that does not meet the definition of Group 1 wastewater stream.

Hazardous air pollutant or *HAP* means one of the chemicals listed in section 112(b) of the Clean Air Act.

Incinerator means an enclosed combustion device that is used for destroying organic compounds. Auxiliary fuel may be used to heat waste gas to combustion temperatures. Any energy recovery section present is not physically formed into one manufactured or assembled unit with the combustion section; rather, the energy recovery section is a separate section following the combustion section and the two are joined by ducts or connections carrying flue gas.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.593(d) of part 60, subpart GGG.

In organic hazardous air pollutant service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP's as determined according to the provisions of §63.180(d) of subpart H of this part and table 1 of this subpart. The provisions of §63.180(d) of subpart H also specify how to determine that a piece of equipment is not in organic HAP service.

Leakless valve means a valve that has no external actuating mechanism.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the stored liquid at the temperature equal to the highest calendar-month average of the liquid storage temperature for liquids stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for liquids stored at the ambient temperature, as determined:

(1) In accordance with methods specified in §63.111 of subpart G of this part;

(2) From standard reference texts; or

(3) By any other method approved by the Administrator.

Miscellaneous process vent means a gas stream containing greater than 20 parts per million by volume organic HAP that is continuously or periodically discharged during normal operation of a petroleum refining process unit meeting the criteria specified in §63.640(a). Miscellaneous process vents include gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device prior to control or discharge to the atmosphere. Miscellaneous process vents include vent streams from: caustic wash accumulators, distillation tower condensers/accumulators, flash/knockout drums, reactor vessels, scrubber overheads, stripper overheads, vacuum (steam) ejectors, wash tower overheads, water wash accumulators, blowdown condensers/accumulators, and delayed coker vents. Miscellaneous process vents do not include:

(1) Gaseous streams routed to a fuel gas system;

(2) Relief valve discharges;

(3) Leaks from equipment regulated under §63.648;

(4) Episodic or nonroutine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring, and catalyst transfer operations;

(5) In situ sampling systems (onstream analyzers);

(6) Catalytic cracking unit catalyst regeneration vents;

(7) Catalytic reformer regeneration vents;

(8) Sulfur plant vents;

(9) Vents from control devices such as scrubbers, boilers, incinerators, and electrostatic precipitators applied to catalytic cracking unit catalyst regeneration vents, catalytic reformer regeneration vents, and sulfur plant vents;

(10) Vents from any stripping operations applied to comply with the wastewater provisions of this subpart, subpart G of this part, or 40 CFR part 61, subpart FF;

(11) Coking unit vents associated with coke drum depressuring at or below a coke drum outlet pressure of 15 pounds per square inch gauge, deheading, draining, or decoking (coke cutting) or pressure testing after decoking;

(12) Vents from storage vessels;

(13) Emissions from wastewater collection and conveyance systems including, but not limited to, wastewater drains, sewer vents, and sump drains; and

(14) Hydrogen production plant vents through which carbon dioxide is removed from process streams or through which steam condensate produced or treated within the hydrogen plant is degassed or deaerated.

Operating permit means a permit required by 40 CFR parts 70 or 71.

Organic hazardous air pollutant or *organic HAP* in this subpart, means any of the organic chemicals listed in table 1 of this subpart.

Petroleum-based solvents means mixtures of aliphatic hydrocarbons or mixtures of one and two ring aromatic hydrocarbons.

Periodically discharged means discharges that are intermittent and associated with routine operations. Discharges associated with maintenance activities or process upsets are not considered periodically discharged miscellaneous process vents and are therefore not regulated by the petroleum refinery miscellaneous process vent provisions.

Petroleum refining process unit means a process unit used in an establishment primarily engaged in petroleum refining as defined in the Standard Industrial Classification code for petroleum refining (2911), and used primarily for the following:

(1) Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;

(2) Separating petroleum; or

(3) Separating, cracking, reacting, or reforming intermediate petroleum streams.

(4) Examples of such units include, but are not limited to, petroleum-based solvent units, alkylation units, catalytic hydrotreating, catalytic hydrorefining, catalytic hydrocracking, catalytic reforming, catalytic cracking, crude distillation, lube oil processing, hydrogen production, isomerization, polymerization, thermal processes, and blending, sweetening, and treating processes. Petroleum refining process units also include sulfur plants.

Plant site means all contiguous or adjoining property that is under common control including properties that are separated only by a road or other public right-of-way. Common control includes properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination thereof.

Primary fuel means the fuel that provides the principal heat input (i.e., more than 50 percent) to the device. To be considered primary, the fuel must be able to sustain operation without the addition of other fuels.

Process heater means an enclosed combustion device that primarily transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

Process unit means the equipment assembled and connected by pipes or ducts to process raw and/or intermediate materials and to manufacture an intended product. A process unit includes any associated storage vessels. For the purpose of this subpart, process unit includes, but is not limited to, chemical manufacturing process units and petroleum refining process units.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours is not considered a process unit shutdown. An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, or would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown is not considered a process unit shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not considered process unit shutdowns.

Recovery device means an individual unit of equipment capable of and used for the purpose of recovering chemicals for use, reuse, or sale. Recovery devices include, but are not limited to, absorbers, carbon adsorbers, and condensers.

Reference control technology for gasoline loading racks means a vapor collection and processing system used to reduce emissions due to the loading of gasoline cargo tanks to 10 milligrams of total organic compounds per liter of gasoline loaded or less.

Reference control technology for marine vessels means a vapor collection system and a control device that reduces captured HAP emissions by 97 percent.

Reference control technology for miscellaneous process vents means a combustion device used to reduce organic HAP emissions by 98 percent, or to an outlet concentration of 20 parts per million by volume.

Reference control technology for storage vessels means either:

(1) An internal floating roof meeting the specifications of §63.119(b) of subpart G except for §63.119 (b)(5) and (b)(6);

(2) An external floating roof meeting the specifications of §63.119(c) of subpart G except for §63.119(c)(2);

(3) An external floating roof converted to an internal floating roof meeting the specifications of §63.119(d) of subpart G except for §63.119(d)(2); or

(4) A closed-vent system to a control device that reduces organic HAP emissions by 95-percent, or to an outlet concentration of 20 parts per million by volume.

(5) For purposes of emissions averaging, these four technologies are considered equivalent.

Reference control technology for wastewater means the use of:

(1) Controls specified in §§61.343 through 61.347 of subpart FF of part 61;

(2) A treatment process that achieves the emission reductions specified in table 7 of this subpart for each individual HAP present in the wastewater stream or is a steam stripper that meets the specifications in §63.138(g) of subpart G of this part; and

(3) A control device to reduce by 95 percent (or to an outlet concentration of 20 parts per million by volume for combustion devices) the organic HAP emissions in the vapor streams vented from treatment processes (including the steam stripper described in paragraph (2) of this definition) managing wastewater.

Refinery fuel gas means a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species (nitrogen, carbon dioxide, hydrogen sulfide, etc.) that is produced in the refining of crude oil and/or petrochemical processes and that is separated for use as a fuel in boilers and process heaters throughout the refinery.

Relief valve means a valve used only to release an unplanned, nonroutine discharge. A relief valve discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

Research and development facility means laboratory and pilot plant operations whose primary purpose is to conduct research and development into new processes and products, where the operations are under the close supervision of technically trained personnel, and is not engaged in the manufacture of products for commercial sale, except in a de minimis manner.

Shutdown means the cessation of a petroleum refining process unit or a unit operation (including, but not limited to, a distillation unit or reactor) within a petroleum refining process unit for purposes including, but not limited to, periodic maintenance, replacement of equipment, or repair.

Startup means the setting into operation of a petroleum refining process unit for purposes of production. Startup does not include operation solely for purposes of testing equipment. Startup does not include changes in product for flexible operation units.

Storage vessel means a tank or other vessel that is used to store organic liquids. Storage vessel does not include:

(1) Vessels permanently attached to motor vehicles such as trucks, railcars, barges, or ships;

(2) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;

(3) Vessels with capacities smaller than 40 cubic meters;

(4) Bottoms receiver tanks; or

(5) Wastewater storage tanks. Wastewater storage tanks are covered under the wastewater provisions.

Temperature monitoring device means a unit of equipment used to monitor temperature and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater.

Total annual benzene means the total amount of benzene in waste streams at a facility on an annual basis as determined in §61.342 of 40 CFR part 61, subpart FF.

Total organic compounds or *TOC,* as used in this subpart, means those compounds excluding methane and ethane measured according to the procedures of Method 18 of 40 CFR part 60, appendix A. Method 25A may be used alone or in combination with Method 18 to measure TOC as provided in §63.645 of this subpart.

Wastewater means water or wastewater that, during production or processing, comes into direct contact with or results from the production or use of any raw material, intermediate product, finished product, byproduct, or waste product and is discharged into any individual drain system. Examples are feed tank drawdown; water formed during a chemical reaction or used as a reactant; water used to wash impurities from organic products or reactants; water used to cool or quench organic vapor streams through direct contact; and condensed steam from jet ejector systems pulling vacuum on vessels containing organics.

§63.642 General standards.

(a) Each owner or operator of a source subject to this subpart is required to apply for a part 70 or part 71 operating permit from the appropriate permitting authority. If the EPA has approved a State operating permit program under part 70, the permit shall be obtained from the State authority. If the State operating permit program has not been approved, the source shall apply to the EPA Regional Office pursuant to part 71.

(c) Table 6 of this subpart specifies the provisions of subpart A of this part that apply and those that do not apply to owners and operators of sources subject to this subpart.

(d) Initial performance tests and initial compliance determinations shall be required only as specified in this subpart.

(1) Performance tests and compliance determinations shall be conducted according to the schedule and procedures specified in this subpart.

(2) The owner or operator shall notify the Administrator of the intention to conduct a performance test at least 30 days before the performance test is scheduled.

(3) Performance tests shall be conducted according to the provisions of §63.7(e) except that performance tests shall be conducted at maximum representative operating capacity for the process. During the performance test, an owner or operator shall operate the control device at either maximum or minimum representative operating conditions for monitored control device parameters, whichever results in lower emission reduction.

(4) Data shall be reduced in accordance with the EPA-approved methods specified in the applicable section or, if other test methods are used, the data and methods shall be validated according to the protocol in Method 301 of appendix A of this part.

(e) Each owner or operator of a source subject to this subpart shall keep copies of all applicable reports and records required by this subpart for at least 5 years except as otherwise specified in this subpart. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

(f) All reports required under this subpart shall be sent to the Administrator at the addresses listed in §63.13 of subpart A of this part. If acceptable to both the Administrator and the owner or operator of a source, reports may be submitted on electronic media.

(g) The owner or operator of an existing source subject to the requirements of this subpart shall control emissions of organic HAP's to the level represented by the following equation:

$E_A = 0.02\Sigma\ EPV_1 + \Sigma\ EPV_2 + 0.05\Sigma\ ES_1 + \Sigma\ ES_2 + \Sigma\ EGLR_{1C} + \Sigma\ EGLR_2 + (R)\ \Sigma\ EMV_1 + \Sigma\ EMV_2 + \Sigma\ EWW_{1C} + \Sigma\ EWW_2$

where:

E_A = Emission rate, megagrams per year, allowed for the source.

$0.02\Sigma\ EPV_1$ = Sum of the residual emissions, megagrams per year, from all Group 1 miscellaneous process vents, as defined in §63.641.

$\Sigma\ EPV_2$ = Sum of the emissions, megagrams per year, from all Group 2 process vents, as defined in §63.641.

$0.05\Sigma\ ES_1$ = Sum of the residual emissions, megagrams per year, from all Group 1 storage vessels, as defined in §63.641.

$\Sigma\ ES_2$ = Sum of the emissions, megagrams per year, from all Group 2 storage vessels, as defined in §63.641.

$\Sigma\ EGLR_{1C}$ = Sum of the residual emissions, megagrams per year, from all Group 1 gasoline loading racks, as defined in §63.641.

$\Sigma\ EGLR_2$ = Sum of the emissions, megagrams per year, from all Group 2 gasoline loading racks, as defined in §63.641.

$(R)\Sigma\ EMV_1$ = Sum of the residual emissions megagrams per year, from all Group 1 marine tank vessels, as defined in §63.641.

R = 0.03 for existing sources, 0.02 for new sources.

$\Sigma\ EMV_2$ = Sum of the emissions, megagrams per year from all Group 2 marine tank vessels, as defined in §63.641.

$\Sigma\ EWW_{1C}$ = Sum of the residual emissions from all Group 1 wastewater streams, as defined in §63.641. This term is calculated for each Group 1 stream according to the equation for EWW_{ic} in §63.652(h)(6).

$\Sigma\ EWW_2$ = Sum of emissions from all Group 2 wastewater streams, as defined in §63.641.

The emissions level represented by this equation is dependent on the collection of emission points in the source. The level is not fixed and can change as the emissions from each emission point change or as the number of emission points in the source changes.

(i) The owner or operator of an existing source shall demonstrate compliance with the emission standard in paragraph (g) of this section by following the procedures specified in paragraph (k) of this section for all emission points, or by following the emissions averaging compliance approach specified in paragraph (l) of this section for specified emission points and the procedures specified in paragraph (k) of this section for all other emission points within the source.

(k) The owner or operator of an existing source may comply, and the owner or operator of a new source shall comply, with the miscellaneous process vent provisions in §§63.643 through 63.645, the storage vessel provisions in §63.646, the wastewater provisions in §63.647, the gasoline loading rack provisions in §63.650, and the marine tank vessel loading operation provisions in §63.651 of this subpart.

(1) The owner or operator using this compliance approach shall also comply with the requirements of §63.654 as applicable.

(2) The owner or operator using this compliance approach is not required to calculate the annual emission rate specified in paragraph (g) of this section.

(m) A State may restrict the owner or operator of an existing source to using only the procedures in paragraph (k) of this section to comply with the emission standard in paragraph (g) of this section. Such a restriction would preclude the source from using an emissions averaging compliance approach.

§63.643 Miscellaneous process vent provisions.

(a) The owner or operator of a Group 1 miscellaneous process vent as defined in §63.641 shall comply with the requirements of either paragraphs (a)(1) or (a)(2) of this section.

(1) Reduce emissions of organic HAP's using a flare that meets the requirements of §63.11(b) of subpart A of this part.

§63.644 Monitoring provisions for miscellaneous process vents.

(a) Except as provided in paragraph (b) of this section, each owner or operator of a Group 1 miscellaneous process vent that uses a combustion device to comply with the requirements in §63.643(a) shall install the monitoring equipment specified in paragraph (a)(1), (a)(2), (a)(3), or (a)(4) of this section, depending on the type of combustion device used. All monitoring equipment shall be installed, calibrated, maintained, and operated according to manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately.

(2) Where a flare is used, a device (including but not limited to a thermocouple, an ultraviolet beam sensor, or an infrared sensor) capable of continuously detecting the presence of a pilot flame is required.

(c) The owner or operator of a Group 1 miscellaneous process vent using a vent system that contains bypass lines that could divert a vent stream away from the control device used to comply with paragraph (a) of this section shall comply with either paragraph (c)(1) or (c)(2) of this section. Equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, pressure relief valves needed for safety reasons, and equipment subject to §63.648 are not subject to this paragraph.

(1) Install, calibrate, maintain, and operate a flow indicator that determines whether a vent stream flow is present at least once every hour. Records shall be generated as specified in §63.654(h) and (i). The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere; or

(2) Secure the bypass line valve in the closed position with a car-seal or a lock-and-key type configuration. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(d) The owner or operator shall establish a range that ensures compliance with the emissions standard for each parameter monitored under paragraphs (a) and (b) of this section. In order to establish the range, the information required in §63.654(f)(3) shall be submitted in the Notification of Compliance Status report.

(e) Each owner or operator of a control device subject to the monitoring provisions of this section shall operate the control device in a manner consistent with the minimum and/or maximum operating parameter value or procedure required to be monitored under paragraphs (a) and (b) of this section. Operation of the control device in a manner that constitutes a period of excess emissions, as defined in §63.654(g)(6), or failure to perform procedures required by this section shall constitute a violation of the applicable emission standard of this subpart.

§63.645 Test methods and procedures for miscellaneous process vents.

(a) To demonstrate compliance with §63.643, an owner or operator shall follow §63.116 except for §63.116 (a)(1), (d) and (e) of subpart G of this part except as provided in paragraphs (b) through (d) and paragraph (i) of this section.

(b) All references to §63.113(a)(1) or (a)(2) in §63.116 of subpart G of this part shall be replaced with §63.643(a)(1) or (a)(2), respectively.

(c) In §63.116(c)(4)(ii)(C) of subpart G of this part, organic HAP's in the list of HAP's in table 1 of this subpart shall be considered instead of the organic HAP's in table 2 of subpart F of this part.

(d) All references to §63.116(b)(1) or (b)(2) shall be replaced with paragraphs (d)(1) and (d)(2) of this section, respectively.

(1) Any boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(2) Any boiler or process heater in which all vent streams are introduced into the flame zone.

(e) For purposes of determining the TOC emission rate, as specified under paragraph (f) of this section, the sampling site shall be after the last product recovery device (as defined in §63.641 of this subpart) (if any recovery devices are present) but prior to the inlet of any control device (as defined in §63.641 of this subpart) that is present, prior to any dilution of the process vent stream, and prior to release to the atmosphere.

(1) Methods 1 or 1A of 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling site.

(2) No traverse site selection method is needed for vents smaller than 0.10 meter in diameter.

(f) Except as provided in paragraph (g) of this section, an owner or operator seeking to demonstrate that a process vent TOC mass flow rate is less than 33 kilograms per day for an existing source or less than 6.8 kilograms per day for a new source in accordance with the Group 2 process vent definition of this subpart shall determine the TOC mass flow rate by the following procedures:

(1) The sampling site shall be selected as specified in paragraph (e) of this section.

(2) The gas volumetric flow rate shall be determined using Methods 2, 2A, 2C, or 2D of 40 CFR part 60, appendix A, as appropriate.

(3) Method 18 or Method 25A of 40 CFR part 60, appendix A shall be used to measure concentration; alternatively, any other method or data that has been validated according to the protocol in Method 301 of appendix A of this part may be used. If Method 25A is used, and the TOC mass flow rate calculated from the Method 25A measurement is greater than or equal to 33 kilograms per day for an existing source or 6.8 kilograms per day for a new source, Method 18 may be used to determine any non-VOC hydrocarbons that may be deducted to calculate the TOC (minus non-VOC hydrocarbons) concentration and mass flow rate. The following procedures shall be used to calculate parts per million by volume concentration:

(i) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) The TOC concentration (C_{TOC}) is the sum of the concentrations of the individual components and shall be computed for each run using the following equation if Method 18 is used:

$$C_{TOC} = \frac{\sum_{i=1}^{x}\left(\sum_{j=1}^{n} C_{ji}\right)}{x}$$

where:

C_{TOC}=Concentration of TOC (minus methane and ethane), dry basis, parts per million by volume.

C_{ji}=Concentration of sample component j of the sample i, dry basis, parts per million by volume.

n=Number of components in the sample.

x=Number of samples in the sample run.

(4) The emission rate of TOC (minus methane and ethane) (E_{TOC}) shall be calculated using the following equation if Method 18 is used:

$$E = K_2 \left[\sum_{j=1}^{n} C_j M_j \right] Q_s$$

where:

E=Emission rate of TOC (minus methane and ethane) in the sample, kilograms per day.

K_2 = Constant, 5.986×10^{-5} (parts per million)$^{-1}$ (gram-mole per standard cubic meter) (kilogram per gram) (minute per day), where the standard temperature (standard cubic meter) is at 20 °C.

C_j=Concentration on a dry basis of organic compound j in parts per million as measured by Method 18 of 40 CFR part 60, appendix A, as indicated in paragraph (f)(3) of this section. C_j includes all organic compounds measured minus methane and ethane.

M_j=Molecular weight of organic compound j, gram per gram-mole.

Q_s=Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 °C.

(5) If Method 25A is used, the emission rate of TOC (E_{TOC}) shall be calculated using the following equation: –

$$E_{TOC} = K_2 C_{TOC} M Q_s$$

where:

E_{TOC}=Emission rate of TOC (minus methane and ethane) in the sample, kilograms per day.

K_2=Constant, 5.986×10^{-5} (parts per million) $^{-1}$ (gram-mole per standard cubic meter) (kilogram per gram)(minute per day), where the standard temperature (standard cubic meter) is at 20 °C.

C_{TOC}=Concentration of TOC on a dry basis in parts per million volume as measured by Method 25A of 40 CFR part 60, appendix A, as indicated in paragraph (f)(3) of this section.

M=Molecular weight of organic compound used to express units of C_{TOC}, gram per gram-mole.

Q_s=Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 °C.

(g) Engineering assessment may be used to determine the TOC emission rate for the representative operating condition expected to yield the highest daily emission rate.

(1) Engineering assessment includes, but is not limited to, the following:

(i) Previous test results provided the tests are representative of current operating practices at the process unit.

(ii) Bench-scale or pilot-scale test data representative of the process under representative operating conditions.

(iii) TOC emission rate specified or implied within a permit limit applicable to the process vent.

(iv) Design analysis based on accepted chemical engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

(A) Use of material balances based on process stoichiometry to estimate maximum TOC concentrations;

(B) Estimation of maximum flow rate based on physical equipment design such as pump or blower capacities; and

(C) Estimation of TOC concentrations based on saturation conditions.

(v) All data, assumptions, and procedures used in the engineering assessment shall be documented.

(h) The owner or operator of a Group 2 process vent shall recalculate the TOC emission rate for each process vent, as necessary, whenever process changes are made to determine whether the vent is in Group 1 or Group 2. Examples of process changes include, but are not limited to, changes in production capacity, production rate, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph, process changes do not include: process upsets; unintentional, temporary process changes; and changes that are within the range on which the original calculation was based.

(1) The TOC emission rate shall be recalculated based on measurements of vent stream flow rate and TOC as specified in paragraphs (e) and (f) of this section, as applicable, or on best engineering assessment of the effects of the change. Engineering assessments shall meet the specifications in paragraph (g) of this section.

(2) Where the recalculated TOC emission rate is greater than 33 kilograms per day for an existing source or greater than 6.8 kilograms per day for a new source, the owner or operator shall submit a report as specified in §63.654 (f), (g), or (h) and shall comply with the appropriate provisions in §63.643 by the dates specified in §63.640.

(i) A compliance determination for visible emissions shall be conducted within 150 days of the compliance date using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

§63.646 Storage vessel provisions.

(a) Each owner or operator of a Group 1 storage vessel subject to this subpart shall comply with the requirements of §§63.119 through 63.121 except as provided in paragraphs (b) through (l) of this section.

(b) As used in this section, all terms not defined in §63.641 shall have the meaning given them in 40 CFR part 63, subparts A or G. The Group 1 storage vessel definition presented in §63.641 shall apply in lieu of the Group 1 storage vessel definitions presented in tables 5 and 6 of §63.119 of subpart G of this part.

(1) An owner or operator may use good engineering judgment or test results to determine the stored liquid weight percent total organic HAP for purposes of group determination. Data, assumptions, and procedures used in the determination shall be documented.

(2) When an owner or operator and the Administrator do not agree on whether the annual average weight percent organic HAP in the stored liquid is above or below 4 percent for a storage vessel at an existing source or above or below 2 percent for a storage vessel at a new source, Method 18 of 40 CFR part 60, appendix A shall be used.

(c) The following paragraphs do not apply to storage vessels at existing sources subject to this subpart: §63.119 (b)(5), (b)(6), (c)(2), and (d)(2).

(d) References shall apply as specified in paragraphs (d)(1) through (d)(10) of this section.

(1) All references to §63.100(k) of subpart F of this part (or the schedule provisions and the compliance date) shall be replaced with §63.640(h),

(2) All references to April 22, 1994 shall be replaced with August 18, 1995.

(3) All references to December 31, 1992 shall be replaced with July 15, 1994.

(4) All references to the compliance dates specified in §63.100 of subpart F shall be replaced with §63.640 (h) through (m).

(5) All references to §63.150 in §63.119 of subpart G of this part shall be replaced with §63.652.

(6) All references to §63.113(a)(2) of subpart G shall be replaced with §63.643(a)(2) of this subpart.

(7) All references to §63.126(b)(1) of subpart G shall be replaced with §63.422(b) of subpart R of this part.

(8) All references to §63.128(a) of subpart G shall be replaced with §63.425, paragraphs (a) through (c) and (e) through (h) of subpart R of this part.

(9) All references to §63.139(d)(1) in §63.120(d)(1)(ii) of subpart G are not applicable. For sources subject to this subpart, such references shall mean that 40 CFR 61.355 is applicable.

(10) All references to §63.139(c) in §63.120(d)(1)(ii) of subpart G are not applicable. For sources subject to this subpart, such references shall mean that §63.647 of this subpart is applicable.

(e) When complying with the inspection requirements of §63.120 of subpart G of this part, owners and operators of storage vessels at existing sources subject to this subpart are not required to comply with the provisions for gaskets, slotted membranes, and sleeve seals.

(f) The following paragraphs (f)(1), (f)(2), and (f)(3) of this section apply to Group 1 storage vessels at existing sources:

(1) If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.

(2) Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting.

(3) Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(g) Failure to perform inspections and monitoring required by this section shall constitute a violation of the applicable standard of this subpart.

(h) References in §§63.119 through 63.121 to §63.122(g)(1), §63.151, and references to initial notification requirements do not apply.

(i) References to the Implementation Plan in §63.120, paragraphs (d)(2) and (d)(3)(i) shall be replaced with the Notification of Compliance Status report.

(j) References to the Notification of Compliance Status report in §63.152(b) shall be replaced with §63.654(f).

(k) References to the Periodic Reports in §63.152(c) shall be replaced with §63.654(g).

(l) The State or local permitting authority can waive the notification requirements of §§63.120(a)(5), 63.120(a)(6), 63.120(b)(10)(ii), and 63.120(b)(10)(iii) for all or some storage vessels at petroleum refineries subject to this subpart. The State or local permitting authority may also grant permission to refill storage vessels sooner than 30 days after submitting the notifications in §§63.120(a)(6) or 63.120(b)(10)(iii) for all storage vessels at a refinery or for individual storage vessels on a case-by-case basis.

§63.647 Wastewater provisions.

(a) Except as provided in paragraph (b) of this section, each owner or operator of a Group 1 wastewater stream shall comply with the requirements of §§61.340 through 61.355 of 40 CFR part 61, subpart FF for each process wastewater stream that meets the definition in §63.641.

(b) As used in this section, all terms not defined in §63.641 shall have the meaning given them in the Clean Air Act or in 40 CFR part 61, subpart FF, §61.341.

(c) Each owner or operator required under subpart FF of 40 CFR part 61 to perform periodic measurement of benzene concentration in wastewater, or to monitor process or control device operating parameters shall operate in a manner consistent with the minimum or maximum (as appropriate) permitted concentration or operating parameter values. Operation of the process, treatment unit, or control device resulting in a measured concentration or operating parameter value outside the permitted limits shall constitute a violation of the emission standards. Failure to perform required leak monitoring for closed vent systems and control devices or failure to repair leaks within the time period specified in subpart FF of 40 CFR part 61 shall constitute a violation of the standard.

§63.648 Equipment leak standards.

(a) Each owner or operator of an existing source subject to the provisions of this subpart shall comply with the provisions of 40 CFR part 60 subpart VV and paragraph (b) of this section except as provided in paragraphs (a)(1), (a)(2), and (c) through (i) of this section. Each owner or operator of a new source subject to the provisions of this subpart shall comply with subpart H of this part except as provided in paragraphs (c) through (i) of this section.

(1) For purposes of compliance with this section, the provisions of 40 CFR part 60, subpart VV apply only to equipment in organic HAP service, as defined in §63.641 of this subpart.

(b) The use of monitoring data generated before August 18, 1995 to qualify for less frequent monitoring of valves and pumps as provided under 40 CFR part 60 subpart VV or subpart H of this part and paragraph (c) of this section (i.e., quarterly or semiannually) is governed by the requirements of paragraphs (b)(1) and (b)(2) of this section.

(1) Monitoring data must meet the test methods and procedures specified in §60.485(b) of 40 CFR part 60, subpart VV or §63.180(b)(1) through (b)(5) of subpart H of this part except for minor departures.

(2) Departures from the criteria specified in §60.485(b) of 40 CFR part 60 subpart VV or §63.180(b)(1) through (b)(5) of subpart H of this part or from the monitoring frequency specified in subpart VV or in paragraph (c) of this section (such as every 6 weeks instead of monthly or quarterly) are minor and do not significantly affect the quality of the data. An example of a minor departure is monitoring at a slightly different frequency (such as every 6 weeks instead of monthly or quarterly). Failure to use a calibrated instrument is not considered a minor departure.

(g) Compressors in hydrogen service are exempt from the requirements of paragraphs (a) and (c) of this section if an owner or operator demonstrates that a compressor is in hydrogen service.

(1) Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service.

(2) For a piece of equipment to be considered in hydrogen service, it must be determined that the percentage hydrogen content can be reasonably expected always to exceed 50 percent by volume.

(i) For purposes of determining the percentage hydrogen content in the process fluid that is contained in or contacts a compressor, the owner or operator shall use either:

(A) Procedures that conform to those specified in §60.593(b)(2) of 40 part 60, subpart GGG.

(B) Engineering judgment to demonstrate that the percentage content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume.

(*1*) When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, the procedures in paragraph (g)(2)(i)(A) of this section shall be used to resolve the disagreement.

(*2*) If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only by following the procedures in paragraph (g)(2)(i)(A) of this section.

(h) Each owner or operator of a source subject to the provisions of this subpart must maintain all records for a minimum of 5 years.

(i) Reciprocating compressors are exempt from seal requirements if recasting the distance piece or compressor replacement is required.

§63.649 Alternative means of emission limitation: Connectors in gas/vapor service and light liquid service.

(e) Delay of repair of connectors for which leaks have been detected is allowed if repair is not technically feasible by normal repair techniques without a process unit shutdown. Repair of this equipment shall occur by the end of the next process unit shutdown.

(1) Delay of repair is allowed for equipment that is isolated from the process and that does not remain in organic HAP service.

(2) Delay of repair for connectors is also allowed if:

(i) The owner or operator determines that emissions of purged material resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair, and

(ii) When repair procedures are accomplished, the purged material would be collected and destroyed or recovered in a control device.

§63.650 Gasoline loading rack provisions.

(a) Except as provided in paragraphs (b) through (c) of this section, each owner or operator of a gasoline loading rack classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a petroleum refinery shall comply with subpart R, §§63.421, 63.422 (a) through (c), 63.425 (a) through (c), 63.425 (e) through (h), 63.427 (a) and (b), and 63.428 (b), (c), (g)(1), and (h)(1) through (h)(3).

(b) As used in this section, all terms not defined in §63.641 shall have the meaning given them in subpart A or in 40 CFR part 63, subpart R. The §63.641 definition of “affected source” applies under this section.

(c) Gasoline loading racks regulated under this subpart are subject to the compliance dates specified in §63.640(h).

§63.651 Marine tank vessel loading operation provisions.

(a) Except as provided in paragraphs (b) through (d) of this section, each owner or operator of a marine tank vessel loading operation located at a petroleum refinery shall comply with the requirements of §§63.560 through 63.567.

(b) As used in this section, all terms not defined in §63.641 shall have the meaning given them in subpart A or in 40 CFR part 63, subpart Y. The §63.641 definition of “affected source” applies under this section.

(c) The Initial Notification Report under §63.567(b) is not required.

(d) The compliance time of 4 years after promulgation of 40 CFR part 63, subpart Y does not apply. The compliance time is specified in §63.640(h)(3).

§63.654 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to the wastewater provisions in §63.647 shall comply with the recordkeeping and reporting provisions in §§61.356 and 61.357 of 40 CFR part 61, subpart FF unless they are complying with the wastewater provisions specified in paragraph (o)(2)(ii) of §63.640. There are no additional reporting and recordkeeping requirements for wastewater under this subpart unless a wastewater stream is included in an emissions average. Recordkeeping and reporting for emissions averages are specified in §63.653 and in paragraphs (f)(5) and (g)(8) of this section.

(b) Each owner or operator subject to the gasoline loading rack provisions in §63.650 shall comply with the recordkeeping and reporting provisions in §63.428 (b) and (c), (g)(1), and (h)(1) through (h)(3) of subpart R of this part. These requirements are summarized in table 4 of this subpart. There are no additional reporting and recordkeeping requirements for gasoline loading racks under this subpart unless a loading rack is included in an emissions average. Recordkeeping and reporting for emissions averages are specified in §63.653 and in paragraphs (f)(5) and (g)(8) of this section.

(c) Each owner or operator subject to the marine tank vessel loading operation standards in §63.651 shall comply with the recordkeeping and reporting provisions in §§63.566 and 63.567(a) and §63.567 (c) through (i) of subpart Y of this part. These requirements are summarized in table 5 of this subpart. There are no additional reporting and recordkeeping requirements for marine tank vessel loading operations under this subpart unless marine tank vessel loading operations are included in an emissions average. Recordkeeping and reporting for emissions averages are specified in §63.653 and in paragraphs (f)(5) and (g)(8) of this section.

(d) Each owner or operator subject to the equipment leaks standards in §63.648 shall comply with the recordkeeping and reporting provisions in paragraphs (d)(1) through (d)(6) of this section.

(1) Sections 60.486 and 60.487 of subpart VV of part 60 except as specified in paragraph (d)(1)(i) of this section; or §§63.181 and 63.182 of subpart H of this part except for §§63.182(b), (c)(2), and (c)(4).

(i) The signature of the owner or operator (or designate) whose decision it was that a repair could not be effected without a process shutdown is not required to be recorded. Instead, the name of the person whose decision it was that a repair could not be effected without a process shutdown shall be recorded and retained for 2 years.

(2) The Notification of Compliance Status report required by §63.182(c) of subpart H and the initial semiannual report required by §60.487(b) of 40 CFR part 60, subpart VV shall be submitted within 150 days of the compliance date specified in §63.640(h); the requirements of subpart H of this part are summarized in table 3 of this subpart.

(3) An owner or operator who determines that a compressor qualifies for the hydrogen service exemption in §63.648 shall also keep a record of the demonstration required by §63.648.

(4) An owner or operator must keep a list of identification numbers for valves that are designated as leakless per §63.648(c)(10).

(5) An owner or operator must identify, either by list or location (area or refining process unit), equipment in organic HAP service less than 300 hours per year within refining process units subject to this subpart.

(6) An owner or operator must keep a list of reciprocating pumps and compressors determined to be exempt from seal requirements as per §§63.648 (f) and (i).

(e) Each owner or operator of a source subject to this subpart shall submit the reports listed in paragraphs (e)(1) through (e)(3) of this section except as provided in paragraph (h)(5) of this section, and shall keep records as described in paragraph (i) of this section.

(1) A Notification of Compliance Status report as described in paragraph (f) of this section;

(2) Periodic Reports as described in paragraph (g) of this section; and

(3) Other reports as described in paragraph (h) of this section.

(f) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status report within 150 days after the compliance dates specified in §63.640(h) with the exception of Notification of Compliance Status reports submitted to comply with §63.640(l)(3) and for storage vessels subject to the compliance schedule specified in §63.640(h)(4). Notification of Compliance Status reports required by §63.640(l)(3) and for storage vessels subject to the compliance dates specified in §63.640(h)(4) shall be submitted according to paragraph (f)(6) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If the required information has been submitted before the date 150 days after the compliance date specified in §63.640(h), a separate Notification of Compliance Status report is not required within 150 days after the compliance dates specified in §63.640(h). If an owner or operator submits the information specified in paragraphs (f)(1) through (f)(5) of this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information. Each owner or operator of a gasoline loading rack classified under Standard Industrial Classification Code 2911 located within a contiguous area and under common control with a petroleum refinery subject to the standards of this subpart shall submit the Notification of Compliance Status report required by subpart R of this part within 150 days after the compliance dates specified in §63.640(h) of this subpart.

(1) The Notification of Compliance Status report shall include the information specified in paragraphs (f)(1)(i) through (f)(1)(v) of this section.

(i) For storage vessels, this report shall include the information specified in paragraphs (f)(1)(i)(A) through (f)(1)(i)(D) of this section.

(A) Identification of each storage vessel subject to this subpart, and for each Group 1 storage vessel subject to this subpart, the information specified in paragraphs (f)(1)(i)(A)(*1*) through (f)(1)(i)(A)(*3*) of this section. This information is to be revised each time a Notification of Compliance Status report is submitted for a storage vessel subject to the compliance schedule specified in §63.640(h)(4) or to comply with §63.640(l)(3).

(*1*) For each Group 1 storage vessel complying with §63.646 that is not included in an emissions average, the method of compliance (i.e., internal floating roof, external floating roof, or closed vent system and control device).

(*2*) For storage vessels subject to the compliance schedule specified in §63.640(h)(4) that are not complying with §63.646, the anticipated compliance date.

(*3*) For storage vessels subject to the compliance schedule specified in §63.640(h)(4) that are complying with §63.646 and the Group 1 storage vessels described in §63.640(l), the actual compliance date.

(B) If a closed vent system and a control device other than a flare is used to comply with §63.646 the owner or operator shall submit:

(*1*) A description of the parameter or parameters to be monitored to ensure that the control device is being properly operated and maintained, an explanation of the criteria used for selection of that parameter (or parameters), and the frequency with which monitoring will be performed; and either

(*2*) The design evaluation documentation specified in §63.120(d)(1)(i) of subpart G, if the owner or operator elects to prepare a design evaluation; or

(*3*) If the owner or operator elects to submit the results of a performance test, identification of the storage vessel and control device for which the performance test will be submitted, and identification of the

emission point(s) that share the control device with the storage vessel and for which the performance test will be conducted.

(C) If a closed vent system and control device other than a flare is used, the owner or operator shall submit:

(*1*) The operating range for each monitoring parameter. The specified operating range shall represent the conditions for which the control device is being properly operated and maintained.

(*2*) If a performance test is conducted instead of a design evaluation, results of the performance test demonstrating that the control device achieves greater than or equal to the required control efficiency. A performance test conducted prior to the compliance date of this subpart can be used to comply with this requirement, provided that the test was conducted using EPA methods and that the test conditions are representative of current operating practices.

(D) If a closed vent system and a flare is used, the owner or operator shall submit:

(*1*) Flare design (e.g., steam-assisted, air-assisted, or nonassisted);

(*2*) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by §63.120(e) of subpart G of this part; and

(*3*) All periods during the compliance determination when the pilot flame is absent.

(ii) For miscellaneous process vents, identification of each miscellaneous process vent subject to this subpart, whether the process vent is Group 1 or Group 2, and the method of compliance for each Group 1 miscellaneous process vent that is not included in an emissions average (e.g., use of a flare or other control device meeting the requirements of §63.643(a)).

(iii) For miscellaneous process vents controlled by control devices required to be tested under §63.645 of this subpart and §63.116(c) of subpart G of this part, performance test results including the information in paragraphs (f)(1)(iii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in §63.645 and that the test conditions are representative of current operating conditions.

(A) The percentage of reduction of organic HAP's or TOC, or the outlet concentration of organic HAP's or TOC (parts per million by volume on a dry basis corrected to 3 percent oxygen), determined as specified in §63.116(c) of subpart G of this part; and

(B) The value of the monitored parameters specified in table 10 of this subpart, or a site-specific parameter approved by the permitting authority, averaged over the full period of the performance test,

(iv) For miscellaneous process vents controlled by flares, performance test results including the information in paragraphs (f)(1)(iv)(A) and (B) of this section;

(A) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by §63.645 of this subpart and §63.116(a) of subpart G of this part, and

(B) A statement of whether a flame was present at the pilot light over the full period of the compliance determination.

(v) For equipment leaks complying with §63.648(c) (i.e., complying with the requirements of subpart H of this part), the Notification of Compliance Report Status report information required by §63.182(c) of subpart H and whether the percentage of leaking valves will be reported on a process unit basis or a sourcewide basis.

(2) If initial performance tests are required by §§63.643 through 63.653 of this subpart, the Notification of Compliance Status report shall include one complete test report for each test method used for a particular source.

(i) For additional tests performed using the same method, the results specified in paragraph (f)(1) of this section shall be submitted, but a complete test report is not required.

(ii) A complete test report shall include a sampling site description, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of calculations, and any other information required by the test method.

(iii) Performance tests are required only if specified by §§63.643 through 63.653 of this subpart. Initial performance tests are required for some kinds of emission points and controls. Periodic testing of the same emission point is not required.

(3) For each monitored parameter for which a range is required to be established under §63.120(d) of subpart G of this part for storage vessels or §63.644 for miscellaneous process vents, the Notification of Compliance Status report shall include the information in paragraphs (f)(3)(i) through (f)(3)(iii) of this section.

(i) The specific range of the monitored parameter(s) for each emission point;

(ii) The rationale for the specific range for each parameter for each emission point, including any data and calculations used to develop the range and a description of why the range ensures compliance with the emission standard.

(A) If a performance test is required by this subpart for a control device, the range shall be based on the parameter values measured during the performance test supplemented by engineering assessments and manufacturer's recommendations. Performance testing is not required to be conducted over the entire range of permitted parameter values.

(B) If a performance test is not required by this subpart for a control device, the range may be based solely on engineering assessments and manufacturers' recommendations.

(iii) A definition of the source's operating day for purposes of determining daily average values of monitored parameters. The definition shall specify the times at which an operating day begins and ends.

(4) Results of any continuous monitoring system performance evaluations shall be included in the Notification of Compliance Status report.

(5) For emission points included in an emissions average, the Notification of Compliance Status report shall include the values of the parameters needed for input to the emission credit and debit equations in §63.652(g) and (h), calculated or measured according to the procedures in §63.652(g) and (h), and the resulting credits and debits for the first quarter of the year. The first quarter begins on the compliance date specified in §63.640.

(6) Notification of Compliance Status reports required by §63.640(l)(3) and for storage vessels subject to the compliance dates specified in §63.640(h)(4) shall be submitted no later than 60 days after the end of the 6-month period during which the change or addition was made that resulted in the Group 1 emission point or the existing Group 1 storage vessel was brought into compliance, and may be combined with the periodic report. Six-month periods shall be the same 6-month periods specified in paragraph (g) of this section. The Notification of Compliance Status report shall include the information specified in paragraphs (f)(1) through (f)(5) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, as part of the periodic report, or in any combination of these four. If the required information has been submitted before the date 60 days after the end of the 6-month period in which the addition of the Group 1 emission point took place, a

separate Notification of Compliance Status report is not required within 60 days after the end of the 6-month period. If an owner or operator submits the information specified in paragraphs (f)(1) through (f)(5) of this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information.

(g) The owner or operator of a source subject to this subpart shall submit Periodic Reports no later than 60 days after the end of each 6-month period when any of the compliance exceptions specified in paragraphs (g)(1) through (g)(6) of this section occur. The first 6-month period shall begin on the date the Notification of Compliance Status report is required to be submitted. A Periodic Report is not required if none of the compliance exceptions specified in paragraphs (g)(1) through (g)(6) of this section occurred during the 6-month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emissions averages, as provided in paragraph (g)(8) of this section. An owner or operator may submit reports required by other regulations in place of or as part of the Periodic Report required by this paragraph if the reports contain the information required by paragraphs (g)(1) through (g)(8) of this section.

(1) For storage vessels, Periodic Reports shall include the information specified for Periodic Reports in paragraph (g)(2) through (g)(5) of this section except that information related to gaskets, slotted membranes, and sleeve seals is not required for storage vessels that are part of an existing source.

(2) An owner or operator who elects to comply with §63.646 by using a fixed roof and an internal floating roof or by using an external floating roof converted to an internal floating roof shall submit the results of each inspection conducted in accordance with §63.120(a) of subpart G of this part in which a failure is detected in the control equipment.

(i) For vessels for which annual inspections are required under §63.120(a)(2)(i) or (a)(3)(ii) of subpart G of this part, the specifications and requirements listed in paragraphs (g)(2)(i)(A) through (g)(2)(i)(C) of this section apply.

(A) A failure is defined as any time in which the internal floating roof is not resting on the surface of the liquid inside the storage vessel and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears, or other openings in the seal or seal fabric; or there are visible gaps between the seal and the wall of the storage vessel.

(B) Except as provided in paragraph (g)(2)(i)(C) of this section, each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made or the date the storage vessel was emptied.

(C) If an extension is utilized in accordance with §63.120(a)(4) of subpart G of this part, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in §63.120(a)(4) of subpart G of this part; and describe the date the storage vessel was emptied and the nature of and date the repair was made.

(ii) For vessels for which inspections are required under §63.120(a)(2)(ii), (a)(3)(i), or (a)(3)(iii) of subpart G of this part (i.e., internal inspections), the specifications and requirements listed in paragraphs (g)(2)(ii)(A) and (g)(2)(ii)(B) of this section apply.

(A) A failure is defined as any time in which the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal (if one has been installed) has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than a 10 percent open area.

(B) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(3) An owner or operator who elects to comply with §63.646 by using an external floating roof shall meet the periodic reporting requirements specified in paragraphs (g)(3)(i) through (g)(3)(iii) of this section.

(i) The owner or operator shall submit, as part of the Periodic Report, documentation of the results of each seal gap measurement made in accordance with §63.120(b) of subpart G of this part in which the seal and seal gap requirements of §63.120(b)(3), (b)(4), (b)(5), or (b)(6) of subpart G of this part are not met. This documentation shall include the information specified in paragraphs (g)(3)(i)(A) through (g)(3)(i)(D) of this section.

(A) The date of the seal gap measurement.

(B) The raw data obtained in the seal gap measurement and the calculations described in §63.120(b)(3) and (b)(4) of subpart G of this part.

(C) A description of any seal condition specified in §63.120(b)(5) or (b)(6) of subpart G of this part that is not met.

(D) A description of the nature of and date the repair was made, or the date the storage vessel was emptied.

(ii) If an extension is utilized in accordance with §63.120(b)(7)(ii) or (b)(8) of subpart G of this part, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in §63.120(b)(7)(ii) or (b)(8) of subpart G of this part, as applicable; and describe the date the vessel was emptied and the nature of and date the repair was made.

(iii) The owner or operator shall submit, as part of the Periodic Report, documentation of any failures that are identified during visual inspections required by §63.120(b)(10) of subpart G of this part. This documentation shall meet the specifications and requirements in paragraphs (g)(3)(iii)(A) and (g)(3)(iii)(B) of this section.

(A) A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than 10 percent open area.

(B) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(4) An owner or operator who elects to comply with §63.646 by using an external floating roof converted to an internal floating roof shall comply with the periodic reporting requirements of paragraph (g)(2) of this section.

(5) An owner or operator who elects to comply with §63.646 by installing a closed vent system and control device shall submit, as part of the next Periodic Report, the information specified in paragraphs (g)(5)(i) through (g)(5)(iii) of this section.

(i) The Periodic Report shall include the information specified in paragraphs (g)(5)(i)(A) and (g)(5)(i)(B) of this section for those planned routine maintenance operations that would require the control device not to meet the requirements of §63.119(e)(1) or (e)(2) of subpart G of this part, as applicable.

(A) A description of the planned routine maintenance that is anticipated to be performed for the control device during the next 6 months. This description shall include the type of maintenance necessary, planned frequency of maintenance, and lengths of maintenance periods.

(B) A description of the planned routine maintenance that was performed for the control device during the previous 6 months. This description shall include the type of maintenance performed and the total number

of hours during those 6 months that the control device did not meet the requirements of §63.119 (e)(1) or (e)(2) of subpart G of this part, as applicable, due to planned routine maintenance.

(ii) If a control device other than a flare is used, the Periodic Report shall describe each occurrence when the monitored parameters were outside of the parameter ranges documented in the Notification of Compliance Status report. The description shall include: Identification of the control device for which the measured parameters were outside of the established ranges, and causes for the measured parameters to be outside of the established ranges.

(iii) If a flare is used, the Periodic Report shall describe each occurrence when the flare does not meet the general control device requirements specified in §63.11(b) of subpart A of this part and shall include: Identification of the flare that does not meet the general requirements specified in §63.11(b) of subpart A of this part, and reasons the flare did not meet the general requirements specified in §63.11(b) of subpart A of this part.

(6) For miscellaneous process vents for which continuous parameter monitors are required by this subpart, periods of excess emissions shall be identified in the Periodic Reports and shall be used to determine compliance with the emission standards.

(i) Period of excess emission means any of the following conditions:

(A) An operating day when the daily average value of a monitored parameter, except presence of a flare pilot flame, is outside the range specified in the Notification of Compliance Status report. Monitoring data recorded during periods of monitoring system breakdown, repairs, calibration checks and zero (low-level) and high-level adjustments shall not be used in computing daily average values of monitored parameters.

(B) An operating day when all pilot flames of a flare are absent.

(C) An operating day when monitoring data required to be recorded in paragraphs (i)(3) (i) and (ii) of this section are available for less than 75 percent of the operating hours.

(D) For data compression systems approved under paragraph (h)(5)(iii) of this section, an operating day when the monitor operated for less than 75 percent of the operating hours or a day when less than 18 monitoring values were recorded.

(ii) For miscellaneous process vents, excess emissions shall be reported for the operating parameters specified in table 10 of this subpart unless other site-specific parameter(s) have been approved by the operating permit authority.

(iii) Periods of startup and shutdown that meet the definition of §63.641, and malfunction that meet the definition in §63.2 and periods of performance testing and monitoring system calibration shall not be considered periods of excess emissions. Malfunctions may include process unit, control device, or monitoring system malfunctions.

(7) If a performance test for determination of compliance for a new emission point subject to this subpart or for an emission point that has changed from Group 2 to Group 1 is conducted during the period covered by a Periodic Report, the results of the performance test shall be included in the Periodic Report.

(i) Results of the performance test shall include the percentage of emissions reduction or outlet pollutant concentration reduction (whichever is needed to determine compliance) and the values of the monitored operating parameters.

(ii) The complete test report shall be maintained onsite.

(8) The owner or operator of a source shall submit quarterly reports for all emission points included in an emissions average.

(i) The quarterly reports shall be submitted no later than 60 calendar days after the end of each quarter. The first report shall be submitted with the Notification of Compliance Status report no later than 150 days after the compliance date specified in §63.640.

(ii) The quarterly reports shall include:

(A) The information specified in this paragraph and in paragraphs (g)(2) through (g)(7) of this section for all storage vessels and miscellaneous process vents included in an emissions average;

(B) The information required to be reported by §63.428 (h)(1), (h)(2), and (h)(3) for each gasoline loading rack included in an emissions average, unless this information has already been submitted in a separate report;

(C) The information required to be included in quarterly reports by §§63.567(f) and 63.567(i)(2) of subpart Y of this part for each marine tank vessel loading operation included in an emissions average, unless the information has already been submitted in a separate report;

(D) Any information pertaining to each wastewater stream included in an emissions average that the source is required to report under the Implementation Plan for the source;

(E) The credits and debits calculated each month during the quarter;

(F) A demonstration that debits calculated for the quarter are not more than 1.30 times the credits calculated for the quarter, as required under §§63.652(e)(4);

(G) The values of any inputs to the credit and debit equations in §63.652 (g) and (h) that change from month to month during the quarter or that have changed since the previous quarter; and

(H) Any other information the source is required to report under the Implementation Plan for the source.

(iii) Every fourth quarterly report shall include the following:

(A) A demonstration that annual credits are greater than or equal to annual debits as required by §63.652(e)(3); and

(B) A certification of compliance with all the emissions averaging provisions in §63.652 of this subpart.

(h) Other reports shall be submitted as specified in subpart A of this part and as follows:

(1) Reports of startup, shutdown, and malfunction required by §63.10(d)(5). Records and reports of startup, shutdown, and malfunction are not required if they pertain solely to Group 2 emission points, as defined in §63.641, that are not included in an emissions average. For purposes of this paragraph, startup and shutdown shall have the meaning defined in §63.641, and malfunction shall have the meaning defined in §63.2; and

(2) For storage vessels, notifications of inspections as specified in paragraphs (h)(2)(i) and (h)(2)(ii) of this section;

(i) In order to afford the Administrator the opportunity to have an observer present, the owner or operator shall notify the Administrator of the refilling of each Group 1 storage vessel that has been emptied and degassed.

(A) Except as provided in paragraphs (h)(2)(i) (B) and (C) of this section, the owner or operator shall notify the Administrator in writing at least 30 calendar days prior to filling or refilling of each storage vessel with organic HAP's to afford the Administrator the opportunity to inspect the storage vessel prior to refilling.

(B) Except as provided in paragraph (h)(2)(i)(C) of this section, if the internal inspection required by §§63.120(a)(2), 63.120(a)(3), or 63.120(b)(10) of subpart G of this part is not planned and the owner or operator could not have known about the inspection 30 calendar days in advance of refilling the vessel

with organic HAP's, the owner or operator shall notify the Administrator at least 7 calendar days prior to refilling of the storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. This notification, including the written documentation, may also be made in writing and sent so that it is received by the Administrator at least 7 calendar days prior to the refilling.

(C) The State or local permitting authority can waive the notification requirements of paragraphs (h)(2)(i)(A) and/or (h)(2)(i)(B) of this section for all or some storage vessels at petroleum refineries subject to this subpart. The State or local permitting authority may also grant permission to refill storage vessels sooner than 30 days after submitting the notification required by paragraph (h)(2)(i)(A) of this section, or sooner than 7 days after submitting the notification required by paragraph (h)(2)(i)(B) of this section for all storage vessels, or for individual storage vessels on a case-by-case basis.

(ii) In order to afford the Administrator the opportunity to have an observer present, the owner or operator of a storage vessel equipped with an external floating roof shall notify the Administrator of any seal gap measurements. The notification shall be made in writing at least 30 calendar days in advance of any gap measurements required by §63.120 (b)(1) or (b)(2) of subpart G of this part. The State or local permitting authority can waive this notification requirement for all or some storage vessels subject to the rule or can allow less than 30 calendar days' notice.

(3) For owners or operators of sources required to request approval for a nominal control efficiency for use in calculating credits for an emissions average, the information specified in §63.652(h).

(4) The owner or operator who requests approval to monitor a different parameter than those listed in §63.644 for miscellaneous process vents or who is required by §63.653(a)(8) to establish a site-specific monitoring parameter for a point in an emissions average shall submit the information specified in paragraphs (h)(4)(i) through (h)(4)(iii) of this section. For new or reconstructed sources, the information shall be submitted with the application for approval of construction or reconstruction required by §63.5(d) of subpart A and for existing sources, and the information shall be submitted no later than 18 months prior to the compliance date. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal.

(i) A description of the parameter(s) to be monitored to determine whether excess emissions occur and an explanation of the criteria used to select the parameter(s).

(ii) A description of the methods and procedures that will be used to demonstrate that the parameter can be used to determine excess emissions and the schedule for this demonstration. The owner or operator must certify that they will establish a range for the monitored parameter as part of the Notification of Compliance Status report required in paragraphs (e) and (f) of this section.

(iii) The frequency and content of monitoring, recording, and reporting if: monitoring and recording are not continuous; or if periods of excess emissions, as defined in paragraph (g)(6) of this section, will not be identified in Periodic Reports required under paragraphs (e) and (g) of this section. The rationale for the proposed monitoring, recording, and reporting system shall be included.

(5) An owner or operator may request approval to use alternatives to the continuous operating parameter monitoring and recordkeeping provisions listed in paragraph (i) of this section.

(i) Requests shall be submitted with the Application for Approval of Construction or Reconstruction for new sources and no later than 18 months prior to the compliance date for existing sources. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal. Requests shall contain the information specified in paragraphs (h)(5)(iii) through (h)(5)(iv) of this section, as applicable.

(ii) The provisions in §63.8(f)(5)(i) of subpart A of this part shall govern the review and approval of requests.

(iii) An owner or operator may request approval to use an automated data compression recording system that does not record monitored operating parameter values at a set frequency (for example, once every hour) but records all values that meet set criteria for variation from previously recorded values.

(A) The requested system shall be designed to:

(*1*) Measure the operating parameter value at least once every hour.

(*2*) Record at least 24 values each day during periods of operation.

(*3*) Record the date and time when monitors are turned off or on.

(*4*) Recognize unchanging data that may indicate the monitor is not functioning properly, alert the operator, and record the incident.

(*5*) Compute daily average values of the monitored operating parameter based on recorded data.

(B) The request shall contain a description of the monitoring system and data compression recording system including the criteria used to determine which monitored values are recorded and retained, the method for calculating daily averages, and a demonstration that the system meets all criteria of paragraph (h)(5)(iii)(A) of this section.

(iv) An owner or operator may request approval to use other alternative monitoring systems according to the procedures specified in §63.8(f) of subpart A of this part.

(6) The owner or operator shall submit the information specified in paragraphs (h)(6)(i) through (h)(6)(iii) of this section, as applicable. For existing sources, this information shall be submitted in the initial Notification of Compliance Status report. For a new source, the information shall be submitted with the application for approval of construction or reconstruction required by §63.5(d) of subpart A of this part. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal.

(i) The determination of applicability of this subpart to petroleum refining process units that are designed and operated as flexible operation units.

(ii) The determination of applicability of this subpart to any storage vessel for which use varies from year to year.

(iii) The determination of applicability of this subpart to any distillation unit for which use varies from year to year.

(i) *Recordkeeping.* (1) Each owner or operator subject to the storage vessel provisions in §63.646 shall keep the records specified in §63.123 of subpart G of this part except as specified in paragraphs (i)(1)(i) through (i)(1)(iv) of this section.

(i) Records related to gaskets, slotted membranes, and sleeve seals are not required for storage vessels within existing sources.

(ii) All references to §63.122 in §63.123 of subpart G of this part shall be replaced with §63.654(e),

(iii) All references to §63.150 in §63.123 of subpart G of this part shall be replaced with §63.652.

(iv) If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources or 2 percent for new sources, a record of any data, assumptions, and procedures used to make this determination shall be retained.

(2) Each owner or operator required to report the results of performance tests under paragraphs (f) and (g)(7) of this section shall retain a record of all reported results as well as a complete test report, as described in paragraph (f)(2)(ii) of this section for each emission point tested.

(3) Each owner or operator required to continuously monitor operating parameters under §63.644 for miscellaneous process vents or under §§63.652 and 63.653 for emission points in an emissions average shall keep the records specified in paragraphs (i)(3)(i) through (i)(3)(v) of this section unless an alternative recordkeeping system has been requested and approved under paragraph (h) of this section.

(i) The monitoring system shall measure data values at least once every hour.

(ii) The owner or operator shall record either:

(A) Each measured data value; or

(B) Block average values for 1 hour or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(iii) Daily average values of each continuously monitored parameter shall be calculated for each operating day and retained for 5 years except as specified in paragraph (i)(3)(iv) of this section.

(A) The daily average shall be calculated as the average of all values for a monitored parameter recorded during the operating day. The average shall cover a 24-hour period if operation is continuous, or the number of hours of operation per day if operation is not continuous.

(B) The operating day shall be the period defined in the Notification of Compliance Status report. It may be from midnight to midnight or another daily period.

(iv) If all recorded values for a monitored parameter during an operating day are within the range established in the Notification of Compliance Status report, the owner or operator may record that all values were within the range and retain this record for 5 years rather than calculating and recording a daily average for that day. For these days, the records required in paragraph (i)(3)(ii) of this section shall also be retained for 5 years.

(v) Monitoring data recorded during periods of monitoring system breakdowns, repairs, calibration checks, and zero (low-level) and high-level adjustments shall not be included in any average computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating.

(4) All other information required to be reported under paragraphs (a) through (h) of this section shall be retained for 5 years.

§ 63.655 Implementation and enforcement.

(a) This subpart can be implemented and enforced by the U.S. EPA, or a delegated authority such as the applicable State, local, or Tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or Tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a State, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or Tribal agency under subpart E of this part, the authorities contained in paragraph (c) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or Tribal agency.

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the requirements in §§63.640, 63.642(g) through (l), 63.643, and 63.646 through 63.652. Where these standards reference another subpart, the cited provisions will be delegated according to the delegation provisions of the referenced subpart. Where these standards reference another subpart and modify the requirements, the requirements shall be modified as described in this

subpart. Delegation of the modified requirements will also occur according to the delegation provisions of the referenced subpart.

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f), as defined in §63.90, and as required in this subpart.

(3) Approval of major alternatives to monitoring under §63.8(f), as defined in §63.90, and as required in this subpart.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f), as defined in §63.90, and as required in this subpart.

Table 1_Hazardous Air Pollutants

Chemical name	CAS No. \a\
Benzene	71432
Biphenyl	92524
Butadiene (1,3)	10990
Carbon disulfide	75150
Carbonyl sulfide	463581
Cresol (mixed isomers \b\)	1319773
Cresol (m-)	108394
Cresol (o-)	95487
Cresol (p-)	106445
Cumene	98828
Dibromoethane (1,2) (ethylene dibromide)	106934
Dichloroethane (1,2)	107062
Diethanolamine	111422
Ethylbenzene	100414
Ethylene glycol	107211
Hexane	110543
Methanol	67561
Methyl ethyl ketone (2-butanone)	78933
Methyl isobutyl ketone (hexone)	108101
Methyl tert butyl ether	1634044
Naphthalene	91203
Phenol	108952
Toluene	108883
Trimethylpentane (2,2,4)	540841
Xylene (mixed isomers \b\)	1330207
xylene (m-)	108383
xylene (o-)	95476
xylene (p-)	106423

\a\ CAS number = Chemical Abstract Service registry number assigned to specific compounds, isomers, or mixtures of compounds.
\b\ Isomer means all structural arrangements for the same number of atoms of each element and does not mean salts, esters, or derivatives.

Table 4 Gasoline Distribution Emission Point Recordkeeping and Reporting Requirements \a\		
Reference (section of subpart R of this part)	Description	Comment
63.428(b)	Records of test results for each gasoline cargo tank loaded at the facility.	
63.428(c)	Continuous monitoring data recordkeeping requirements.	
63.428(g)(1)	Semiannual report loading rack information.	Required to be submitted with the periodic report required under 40 CFR part 63 subpart CC.
63.428 (h)(1) through (h)(3)	Excess emissions report loading rack information.	Required to be submitted with the periodic report required under 40 CFR part 63 subpart CC.
a This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.		

Table 5 Marine Vessel Loading and Unloading Operations Recordkeeping and Reporting Requirements \a\		
Reference (section of subpart Y of this part)	Description	Comment
63.565(a)	Performance test/site test plan.	The information required under this paragraph is to be submitted with the notification of compliance status report required under 40 CFR part 63, subpart CC.
63.565(b)	Performance test data requirements	
63.567(a)	General Provisions (subpart A) applicability	
63.567(c)	Vent system valve bypass recordkeeping requirements	
63.567(d)	Continuous equipment monitoring recordkeeping requirements	
63.567(e)	Flare recordkeeping requirements	
63.567(f)	Quarterly report requirements	The information required under this paragraph is to be submitted with the periodic report required under 40 CFR part 63 subpart CC.
63.567(g)	Marine vessel vapor-tightness documentation	
63.567(h)	Documentation file maintenance	
63.567(i)	Emission estimation reporting and recordkeeping procedures	
a This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.		

Table 6_General Provisions Applicability to Subpart CC \a\		
Reference	Applies to subpart CC	Comment
63.1(a)(1)	Yes	
63.1(a)(2)	Yes	
63.1(a)(3)	Yes	
63.1(a)(4)	No	Subpart CC (this table) specifies applicability of each paragraph in subpart A to subpart CC.
63.1(a)(5)-63.1(a)(9)	No	
63.1(a)(10)	No	Subpart CC and other cross-referenced subparts specify calendar or operating day.
63.1(a)(11)	Yes	
63.1(a)(12)	Yes	
63.1(a)(13)	Yes	
63.1(a)(14)	Yes	
63.1(b)(1)	No	Subpart CC specifies its own applicability.
63.1(b)(2)	Yes	
63.1(b)(3)	No	
63.1(c)(1)	No	Subpart CC explicitly specifies requirements that apply.
63.1(c)(2)	No	Area sources are not subject to subpart CC.
63.1(c)(3)	No	
63.1(c)(4)	Yes	
63.1(c)(5)	Yes	Except that sources are not required to submit notifications overridden by this table.
63.1(d)	No	
63.1(e)	No	
63.2	Yes	§ 63.641 of subpart CC specifies that if the same term is defined in subparts A and CC, it shall have the meaning given in subpart CC.
63.3	No	Units of measure are spelled out in subpart CC.
63.4(a)(1)-63.4(a)(3)	Yes	
63.4(a)(4)	No	Reserved.
63.4(a)(5)	Yes	
63.4(b)	Yes	
63.4(c)	Yes	
63.5(a)(1)	Yes	Except replace term "source" and "stationary source" in § 63.5(a)(1) of subpart A with "affected source."
63.5(a)(2)	Yes	
63.5(b)(1)	Yes	
63.5(b)(2)	No	Reserved.
63.5(b)(3)	Yes	
63.5(b)(4)	Yes	Except the cross- reference to § 63.9(b) is changed to § 63.9(b) (4) and (5). Subpart CC overrides § 63.9 (b)(2) and (b)(3).
63.5(b)(5)	Yes	
63.5(b)(6)	Yes	
63.5(c)	No	Reserved.
63.5(d)(1)(i)	Yes	Except that the application shall be submitted as soon as practicable before startup but no later than 90 days (rather than 60 days) after the promulgation date of subpart CC if the construction or reconstruction had commenced and initial startup had not occurred before the promulgation of subpart CC.
63.5(d)(1)(ii)	Yes	Except that for affected sources subject to subpart CC, emission estimates specified in § 63.5(d)(1)(ii)(H) are not required.
63.5(d)(1)(iii)	No	Subpart CC requires submittal of the notification of compliance status report in § 63.654(e).
63.5(d)(2)	No	

Table 6_General Provisions Applicability to Subpart CC \a\		
Reference	Applies to subpart CC	Comment
63.5(d)(3)	Yes	Except § 63.5(d)(3)(ii) does not apply.
63.5(d)(4)	Yes	
63.5(e)	Yes	
63.5(f)(1)	Yes	
63.5(f)(2)	Yes	Except that the "60 days" in the cross- referenced § 63.5(d)(1) is changed to "90 days," and the cross-reference to (b)(2) does not apply.
63.6(a)	Yes	
63.6(b)(1)	No	Subpart CC specifies compliance dates for sources subject to subpart CC.
63.6(b)(2)	No	
63.6(b)(3)	Yes	
63.6(b)(4)	No	May apply when standards are proposed under section 112(f) of the Clean Air Act.
63.6(b)(5)	No	§ 63.654(d) of subpart CC includes notification requirements.
63.6(b)(6)	No	
63.6(b)(7)	No	
63.6(c)(1)	No	§ 63.640 of subpart CC specifies the compliance date.
63.6(c)(2)-63.6(c)(4)	No	
63.6(c)(5)	Yes	
63.6(d)	No	
63.6(e)	Yes	Does not apply to Group 2 emission points. \b\ The startup, shutdown, and malfunction plan specified in § 63.6(e)(3) is not required for wastewater operations that are not subject to subpart G of this part. Except that actions taken during a startup, shutdown, or malfunction that are not consistent with the startup, shutdown, and malfunction plan do not need to be reported within 2 and 7 days of commencing and completing the action, respectively, but must be included in the next periodic report.
63.6(f)(1)	Yes	
63.6(f)(2)(i)	Yes	
63.6(f)(2)(ii)	Yes	Subpart CC specifies the use of monitoring data in determining compliance with subpart CC.
63.6(f)(2)(iii) (A), (B), and (C)	Yes	
63.6(f)(2)(iii)(D)	No	
63.6(f)(2)(iv)	Yes	
63.6(f)(2)(v)	Yes	
63.6(f)(3)	Yes	
63.6(g)	Yes	
63.6(h) (1) and (2)	Yes	
63.6(h) (4) and (5)	No	Visible emission requirements and timing in subpart CC.
63.6(h)(6)	Yes	
63.6(h) (7) through (9)	No	Subpart CC does not require opacity standards.
63.6(i)	Yes	Except for § 63.6(i)(15), which is reserved.
63.6(j)	Yes	
63.7(a)(1)	No	Subpart CC specifies required testing and compliance demonstration procedures.

Table 6_General Provisions Applicability to Subpart CC \a\		
Reference	Applies to subpart CC	Comment
63.7(a)(2)	No	Test results must be submitted in the notification of compliance status report due 150 days after compliance date, as specified in § 63.654(d) of subpart CC.
63.7(a)(3)	Yes	
63.7(b)	No	
63.7(c)	No	
63.7(d)	Yes	
63.7(e)(1)	Yes	
63.7(e)(2)	Yes	
63.7(e)(3)	No	Subpart CC specifies test methods and procedures.
63.7(e)(4)	Yes	
63.7(f)	No	Subpart CC specifies applicable methods and provides alternatives.
63.7(g)	No	Performance test reporting specified in § 63.654(d).
63.7(h)(1)	Yes	
63.7(h)(2)	Yes	
63.7(h)(3)	Yes	Yes, except site- specific test plans shall not be required, and where § 63.7(g)(3) specifies submittal by the date the site- specific test plan is due, the date shall be 90 days prior to the notification of compliance status report in § 63.654(d).
63.7(h)(4)	No	
63.7(h)(5)	Yes	
63.8(a)	No	
63.8(b)(1)	Yes	
63.8(b)(2)	No	Subpart CC specifies locations to conduct monitoring.
63.8(b)(3)	Yes	
63.8(c)(1)(i)	Yes	
63.8(c)(1)(ii)	No	Addressed by periodic reports in § 63.654(e) of subpart CC.
63.8(c)(1)(iii)	Yes	
63.8(c)(2)	Yes	
63.8(c)(3)	Yes	Except that verification of operational status shall, at a minimum, include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment would monitor accurately.
63.8(c)(4)	No	Subpart CC specifies monitoring frequency in § 63.641 and § 63.654(g)(3) of subpart CC.
63.8(c)(5)-63.8(c)(8)	No	
63.8(d)	No	
63.8(e)	No	
63.8(f)(1)	Yes	
63.8(f)(2)	Yes	
63.8(f)(3)	Yes	
63.8(f)(4)(i)	No	Timeframe for submitting request is specified in § 63.654(f)(4) of subpart CC.
63.8(f)(4)(ii)	Yes	
63.8(f)(4)(iii)	No	
63.8(f)(5)(i)	Yes	
63.8(f)(5)(ii)	No	
63.8(f)(5)(iii)	Yes	
63.8(f)(6)	No	Subpart CC does not require continuous emission monitors.
63.8(g)	No	Subpart CC specifies data reduction procedures in § 63.654(h)(3).

Table 6_General Provisions Applicability to Subpart CC \a\		
Reference	Applies to subpart CC	Comment
63.9(a)	Yes	Except that the owner or operator does not need to send a copy of each notification submitted to the Regional Office of the EPA as stated in § 63.9(a)(4)(ii).
63.9(b)(1)(i)	No	Specified in § 63.654(d)(2) of subpart CC.
63.9(b)(1)(ii)	No	
63.9(b)(2)	No	An initial notification report is not required under subpart CC.
63.9(b)(3)	No	
63.9(b)(4)	Yes	Except that the notification in § 63.9(b)(4)(i) shall be submitted at the time specified in § 63.654(d)(2) of subpart CC.
63.9(b)(5)	Yes	Except that the notification in § 63.9(b)(5) shall be submitted at the time specified in § 63.654(d)(2) of subpart CC.
63.9(c)	Yes	
63.9(d)	Yes	
63.9(e)	No	
63.9(f)	No	
63.9(g)	No	
63.9(h)	No	Subpart CC § 63.652(d) specifies notification of compliance status report requirements.
63.9(i)	Yes	
63.9(j)	No	
63.10(a)	Yes	
63.10(b)(1)	No	§ 63.644(d) of subpart CC specifies record retention requirements.
63.10(b)(2)(i)	Yes	
63.10(b)(2)(ii)	Yes	
63.10(b)(2)(iii)	No	
63.10(b)(2)(iv)	Yes	
63.10(b)(2)(v)	Yes	
63.10(b)(2)(vi)-(ix)	No	
63.10(b)(2)(x)	Yes	
63.10(b)(2)(xii)-(xiv)	No	
63.10(b)(3)	No	
63.10(c)	No	
63.10(d)(1)	No	
63.10(d)(2)	No	§ 63.654(d) of subpart CC specifies performance test reporting.
63.10(d)(3)	No	
63.10(d)(4)	Yes	
63.10(d)(5)(i)	Yes \b\	Except that reports required by § 63.10(d)(5)(i) may be submitted at the same time as periodic reports specified in § 63.654(e) of subpart CC.
63.10(d)(5)(ii)	Yes	Except that actions taken during a startup, shutdown, or malfunction that are not consistent with the startup, shutdown, and malfunction plan do not need to be reported within 2 and 7 days of commencing and completing the action, respectively, but must be included in the next periodic report.
63.10(e)	No	
63.10(f)	Yes	
63.11-63.15	Yes	

\a\ Wherever subpart A specifies "postmark" dates, submittals may be sent by methods other than the U.S. Mail (e.g., by fax or courier). Submittals shall be sent by the specified dates, but a postmark is not required.

\b\ The plan, and any records or reports of startup, shutdown, and malfunction do not apply to Group 2 emission points.

E.1.3 Deadlines Relating to National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries [40 CFR Part 63, Subpart CC]

The Permittee shall comply with the below requirements by the dates listed for storage tanks TK-3573, TK-SP-1 through TK-SP-4, TK-LG-1 through TK-LG-17, and TK-3570, which are considered part of an existing affected source.

Requirement	Rule Citations	Applicable To	Deadline
Initial Semiannual Compliance Report	40 CFR 63.654(g)	Pumps, Valves, and Connectors at the Tank Cleaning Facility	In the next semi-annual report submitted for the existing equipment at the refinery after startup of the new equipment
Notification of Compliance Status report for emission points that are added or changed	40 CFR 63.640(l)(3) 40 CFR 63.654(f)(1)(i)(A) 40 CFR 63.9(h)	New Group 2 Storage Tanks(1)	Submitted in the next Notification of Compliance Status for the existing affected source (after startup of the new Group 2 storage tanks) or Submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three

(1) Group 2 storage tanks include storage tanks TK-3573, TK-SP-1 through TK-SP-4, TK-LG-1 through TK-LG-17, and TK-3570.

SECTION E.2 40 CFR Part 60, Subpart J - Standards of Performance for Petroleum Refineries

E.2.1 General Provisions Relating to NSPS Subpart J [326 IAC 12-1] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR Part 60, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the affected emission units at this source, except when otherwise specified in 40 CFR Part 60, Subpart J.

E.2.2 NSPS Subpart J Requirements [40 CFR Part 60, Subpart J] [326 IAC 12]

Pursuant to 40 CFR 60.100(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart J, which are incorporated by reference as 326 IAC 12, for the fuel gas combustion devices and Claus sulfur recovery plants, except when otherwise specified in 40 CFR Part 60, Subpart J.

Subpart J—Standards of Performance for Petroleum Refineries

§ 60.100 Applicability, designation of affected facility, and reconstruction.

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants of 20 long tons per day (LTD) or less. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section which commences construction or modification after June 11, 1973, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction or modification after October 4, 1976, is subject to the requirements of this subpart except as provided under paragraphs (c) and (d) of this section.

(c) Any fluid catalytic cracking unit catalyst regenerator under paragraph (b) of this section which commences construction or modification on or before January 17, 1984, is exempted from §60.104(b).

(d) Any fluid catalytic cracking unit in which a contact material reacts with petroleum derivatives to improve feedstock quality and in which the contact material is regenerated by burning off coke and/or other deposits and that commences construction or modification on or before January 17, 1984, is exempt from this subpart.

(e) For purposes of this subpart, under §60.15, the “fixed capital cost of the new components” includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following January 17, 1984. For purposes of this paragraph, “commenced” means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.104 Standards for sulfur oxides.

Each owner or operator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall:

(1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released

to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

(2) Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of:

(i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air.

(ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air.

§ 60.105 Monitoring of emissions and operations.

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(4) In place of the SO_2 monitor in paragraph (a)(3) of this section, an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H_2S.

(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

(iii) The performance evaluations for this H_2S monitor under §60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(5) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to §60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 500 ppm SO_2 and 25 percent O_2.

(ii) The performance evaluations for this SO_2 monitor under §60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(6) For Claus sulfur recovery plants with reduction control systems not followed by incineration subject to §60.104(a)(2)(ii), an instrument for continuously monitoring and recording the concentration of reduced sulfur and O_2 emissions into the atmosphere. The reduced sulfur emissions shall be calculated as SO_2 (dry basis, zero percent excess air).

(i) The span values for this monitor are 450 ppm reduced sulfur and 25 percent O_2.

(ii) The performance evaluations for this reduced sulfur (and O_2) monitor under §60.13(c) shall use Performance Specification 5 of Appendix B of this Part (and Performance Specification 3 of Appendix B of this Part for the O_2 analyzer). Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations. If Method 3 yields O_2 concentrations below 0.25 percent during the performance specification test, the O_2 concentration may be assumed to be zero and the reduced sulfur CEMS need not include an O_2 monitor.

(e) For the purpose of reports under §60.7(c), periods of excess emissions that shall be determined and reported are defined as follows:

Note: All averages, except for opacity, shall be determined as the arithmetic average of the applicable 1-hour averages, e.g., the rolling 3-hour average shall be determined as the arithmetic average of three contiguous 1-hour averages.

(3) *Sulfur dioxide from fuel gas combustion.*

(ii) All rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under §60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

(4) *Sulfur dioxide from Claus sulfur recovery plants.* (i) All 12-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system under §60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air); or

(ii) All 12-hour periods during which the average concentration of reduced sulfur (as SO_2) as measured by the reduced sulfur continuous monitoring system under §60.105(a)(6) exceeds 300 ppm; or

§ 60.106 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(e)(1) The owner or operator shall determine compliance with the H_2S standard in §60.104(a)(1) as follows: Method 11, 15, 15A, or 16 shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line.

(i) For Method 11, the sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

(ii) For Method 15 or 16, at least three injects over a 1-hour period shall constitute a run.

(iii) For Method 15A, a 1-hour sample shall constitute a run.

(f) The owner or operator shall determine compliance with the SO_2 and the H_2S and reduced sulfur standards in §60.104(a)(2) as follows:

(1) Method 6 shall be used to determine the SO_2 concentration. The concentration in mg/dscm obtained by Method 6 or 6C is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5.00 m^2 (53.8 ft^2) or at a point no closer to the walls than 1.00 m (39.4 in.) if the cross-sectional area is 5.00 m^2 or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of these eight samples shall constitute a run. For Method 6C, a run shall consist of the arithmetic average of four 1-hour samples. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C. The sampling time for each sample shall be equal to the time it takes for two Method 6 samples. The moisture content from this sample shall be used to correct the corresponding Method 6 samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 shall be used following the procedures of paragraph (f)(2) of this section.

(2) Method 15 shall be used to determine the reduced sulfur and H_2 S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The SO_2 equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO_2 equivalent for each sample during the run. Method 4 shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

(3) The oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 or 3A. The samples shall be taken simultaneously with the SO_2, reduced sulfur and H_2S, or moisture samples. The SO_2, reduced sulfur, and H_2S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(6) of this section.

(h)(6) For the purpose of adjusting pollutant concentrations to zero percent oxygen, the following equation shall be used:

$C_{adj}=C_{meas}[20.9_c/(20.9-\%O_2)]$

where:

C_{adj}=pollutant concentration adjusted to zero percent oxygen, ppm or g/dscm

C_{meas}=pollutant concentration measured on a dry basis, ppm or g/dscm

20.9_c=20.9 percent oxygen−0.0 percent oxygen (defined oxygen correction basis), percent

20.9=oxygen concentration in air, percent

$\%O_2$=oxygen concentration measured on a dry basis, percent

§ 60.107 Reporting and recordkeeping requirements.

(d) For any periods for which sulfur dioxide or oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(e) The owner or operator of an affected facility shall submit the reports required under this subpart to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(f) The owner or operator of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.

E.2.3 One Time Deadlines Relating to NSPS Subpart J

The Permittee shall comply with the following requirements by the dates listed below:

Requirement	Rule Citation	Affected Facility	Deadline

Requirement	Rule Citation	Affected Facility	Deadline
Notification of the date of construction commencement	40 CFR 60.7(a)(1)	Catalytic Oxidizer F-1	No later than 30 days after commencement of construction
Complete Performance Tests	40 CFR 60.8	Catalytic Oxidizer F-1	Within 60-days after achieving maximum production rate but not later than 180-days after initial startup
Notification of initial startup	40 CFR 60.7(a)(3)	Catalytic Oxidizer F-1	Within 15 days of startup
Notification of the date of demonstration of continuous monitoring system performance	40 CFR 60.7(a)(5)	Catalytic Oxidizer F-1	30-days prior to demonstration

SECTION E.3 40 CFR Part 61, Subpart FF – National Emission Standards for Benzene Waste Operations

E.3.1 General Provisions Relating to NESHAP Subpart FF [326 IAC 14-1] [40 CFR Part 61, Subpart A]

Pursuant to 40 CFR Part 61(c), the Permittee shall comply with the provisions of 40 CFR Part 61, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 14-1, except when otherwise specified in 40 CFR Part 61, Subpart FF.

E.3.2 NESHAP Subpart FF Requirements [40 CFR Part 61, Subpart FF] [326 IAC 14]

Pursuant to 40 CFR 61.340(a), the Permittee shall comply with the provisions of 40 CFR Part 61, Subpart FF, which are incorporated by reference as 326 IAC 14, for tanks, containers, individual drain systems, oil-water separators, treatment processes, and closed vent systems that are used for benzene waste operations, as specified below:

Subpart FF—National Emission Standard for Benzene Waste Operations

§61.340 Applicability.

(a) The provisions of this subpart apply to owners and operators of chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries.

(b) The provisions of this subpart apply to owners and operators of hazardous waste treatment, storage, and disposal facilities that treat, store, or dispose of hazardous waste generated by any facility listed in paragraph (a) of this section. The waste streams at hazardous waste treatment, storage, and disposal facilities subject to the provisions of this subpart are the benzene-containing hazardous waste from any facility listed in paragraph (a) of this section. A hazardous waste treatment, storage, and disposal facility is a facility that must obtain a hazardous waste management permit under subtitle C of the Solid Waste Disposal Act.

(c) At each facility identified in paragraph (a) or (b) of this section, the following waste is exempt from the requirements of this subpart:

(1) Waste in the form of gases or vapors that is emitted from process fluids:

(2) Waste that is contained in a segregated stormwater sewer system.

§61.342 Standards: General.

(a) An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of paragraphs (b) and (c) of this section. The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream is to be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows:

(1) Wastes that are exempted from control under §§61.342(c)(2) and 61.342(c)(3) are included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(2) The benzene in a material subject to this subpart that is sold is included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent.

(3) Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recovery of product from soil or groundwater, are not included in the calculation of total annual benzene quantity for that facility. If the facility's total annual benzene quantity is 10 Mg/yr (11 ton/yr) or more, wastes generated by remediation activities are subject to the requirements of paragraphs (c) through (h) of this section. If the facility is managing remediation waste generated offsite, the benzene in this waste shall be included in the calculation of total annual benzene quantity in facility waste, if the waste streams have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(4) The total annual benzene quantity is determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in §61.355(c)(1)(i) (A) through (C).

(b) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall be in compliance with the requirements of paragraphs (c) through (h) of this section no later than 90 days following the effective date, unless a waiver of compliance has been obtained under §61.11, or by the initial startup for a new source with an initial startup after the effective date.

(c) (1) For each waste stream that contains benzene, including (but not limited to) organic waste streams that contain less than 10 percent water and aqueous waste streams, even if the wastes are not discharged to an individual drain system, the owner or operator shall:

(i) Remove or destroy the benzene contained in the waste using a treatment process or wastewater treatment system that complies with the standards specified in §61.348 of this subpart.

(ii) Comply with the standards specified in §§61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste stream prior to and during treatment of the waste stream in accordance with paragraph (c)(1)(i) of this section.

(iii) Each waste management unit used to manage or treat waste streams that will be recycled to a process shall comply with the standards specified in §§61.343 through 61.347. Once the waste stream is recycled to a process, including to a tank used for the storage of production process feed, product, or product intermediates, unless this tank is used primarily for the storage of wastes, the material is no longer subject to paragraph (c) of this section.

(c) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall manage and treat the facility waste as follows:

(2) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the flow-weighted annual average benzene concentration for the waste stream is less than 10 ppmw as determined by the procedures specified in §61.355(c)(2) or §61.355(c)(3).

(3) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the conditions specified in either paragraph (c)(3)(i) or (c)(3)(ii) of this section are met.

(i) The waste stream is process wastewater that has a flow rate less than 0.02 liters per minute (0.005 gallons per minute) or an annual wastewater quantity of less than 10 Mg/yr (11 ton/yr); or

(ii) All of the following conditions are met:

(A) The owner or operator does not choose to exempt process wastewater under paragraph (c)(3)(i) of this section,

(B) The total annual benzene quantity in all waste streams chosen for exemption in paragraph (c)(3)(ii) of this section does not exceed 2.0 Mg/yr (2.2 ton/yr) as determined in the procedures in §61.355(j), and

(C) The total annual benzene quantity in a waste stream chosen for exemption, including process unit turnaround waste, is determined for the year in which the waste is generated.

(e) As an alternative to the requirements specified in paragraphs (c) and (d) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste with a flow-weighted annual average water content of less than 10 percent in accordance with the requirements of paragraph (c)(1) of this section; and

(2) The owner or operator shall manage and treat facility waste (including remediation and process unit turnaround waste) with a flow-weighted annual average water content of 10 percent or greater, on a volume basis as total water, and each waste stream that is mixed with water or wastes at any time such that the resulting mixture has an annual water content greater than 10 percent, in accordance with the following:

(i) The benzene quantity for the wastes described in paragraph (e)(2) of this section must be equal to or less than 6.0 Mg/yr (6.6 ton/yr), as determined in §61.355(k). Wastes as described in paragraph (e)(2) of this section that are transferred offsite shall be included in the determination of benzene quantity as provided in §61.355(k). The provisions of paragraph (f) of this section shall not apply to any owner or operator who elects to comply with the provisions of paragraph (e) of this section.

(ii) The determination of benzene quantity for each waste stream defined in paragraph (e)(2) of this section shall be made in accordance with §61.355(k).

(f) Rather than treating the waste onsite, an owner or operator may elect to comply with paragraph (c)(1)(i) of this section by transferring the waste offsite to another facility where the waste is treated in accordance with the requirements of paragraph (c)(1)(i) of this section. The owner or operator transferring the waste shall:

(1) Comply with the standards specified in §§61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste prior to shipment of the waste offsite.

(2) Include with each offsite waste shipment a notice stating that the waste contains benzene which is required to be managed and treated in accordance with the provisions of this subpart.

(g) Compliance with this subpart will be determined by review of facility records and results from tests and inspections using methods and procedures specified in §61.355 of this subpart.

§61.343 Standards: Tanks.

(a) Except as provided in paragraph (b) of this section and in §61.351, the owner or operator must meet the standards in paragraph (a)(1) or (2) of this section for each tank in which the waste stream is placed in accordance with §61.342 (c)(1)(ii). The standards in this section apply to the treatment and storage of the waste stream in a tank, including dewatering.

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the tank to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the tank except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the tank is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(*1*) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(*2*) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h); and

(*3*) The pressure is monitored continuously to ensure that the pressure in the tank remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of §61.349 of this subpart.

(b) For a tank that meets all the conditions specified in paragraph (b)(1) of this section, the owner or operator may elect to comply with paragraph (b)(2) of this section as an alternative to the requirements specified in paragraph (a)(1) of this section.

(1) The waste managed in the tank complying with paragraph (b)(2) of this section shall meet all of the following conditions:

(i) Each waste stream managed in the tank must have a flow-weighted annual average water content less than or equal to 10 percent water, on a volume basis as total water.

(ii) The waste managed in the tank either:

(A) Has a maximum organic vapor pressure less than 5.2 kilopascals (kPa) (0.75 pounds per square inch (psi));

(B) Has a maximum organic vapor pressure less than 27.6 kPa (4.0 psi) and is managed in a tank having design capacity less than 151 m^3 (40,000 gal); or

(C) Has a maximum organic vapor pressure less than 76.6 kPa (11.1 psi) and is managed in a tank having a design capacity less than 75 m^3 (20,000 gal).

(2) The owner or operator shall install, operate, and maintain a fixed roof as specified in paragraph (a)(1)(i).

(3) For each tank complying with paragraph (b) of this section, one or more devices which vent directly to the atmosphere may be used on the tank provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the tank or cover resulting from filling or emptying the tank, diurnal temperature changes, atmospheric pressure changes or malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(c) Each fixed-roof, seal, access door, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access doors and other openings are closed and gasketed properly.

(d) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 45 calendar days after identification.

§61.345 Standards: Containers.

(a) The owner or operator shall meet the following standards for each container in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a cover on each container used to handle, transfer, or store waste in accordance with the following requirements:

(i) The cover and all openings (e.g., bungs, hatches, and sampling ports) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(ii) Except as provided in paragraph (a)(4) of this section, each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the container except when it is necessary to use the opening for waste loading, removal, inspection, or sampling.

(2) When a waste is transferred into a container by pumping, the owner or operator shall perform the transfer using a submerged fill pipe. The submerged fill pipe outlet shall extend to within two fill pipe diameters of the bottom of the container while the container is being loaded. During loading of the waste, the cover shall remain in place and all openings shall be maintained in a closed, sealed position except for those openings required for the submerged fill pipe, those openings required for venting of the container to prevent physical damage or permanent deformation of the container or cover, and any openings complying with paragraph (a)(4) of this section.

(b) Each cover and all openings shall be visually inspected initially and quarterly thereafter to ensure that they are closed and gasketed properly.

(c) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

§61.346 Standards: Individual drain systems.

(a) Except as provided in paragraph (b) of this section, the owner or operator shall meet the following standards for each individual drain system in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each drain system opening a cover and closed-vent system that routes all organic vapors vented from the drain system to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the drain system except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the individual drain system is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(*1*) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(*2*) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h); and

(*3*) The pressure is monitored continuously to ensure that the pressure in the individual drain system remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with §61.349 of this subpart.

(2) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(3) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

(b) As an alternative to complying with paragraph (a) of this section, an owner or operator may elect to comply with the following requirements:

(1) Each drain shall be equipped with water seal controls or a tightly sealed cap or plug.

(2) Each junction box shall be equipped with a cover and may have a vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.

(i) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.

(ii) One of the following methods shall be used to control emissions from the junction box vent pipe to the atmosphere:

(A) Equip the junction box with a system to prevent the flow of organic vapors from the junction box vent pipe to the atmosphere during normal operation. An example of such a system includes use of water seal controls on the junction box. A flow indicator shall be installed, operated, and maintained on each junction box vent pipe to ensure that organic vapors are not vented from the junction box to the atmosphere during normal operation.

(B) Connect the junction box vent pipe to a closed-vent system and control device in accordance with §61.349 of this subpart.

(3) Each sewer line shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

(4) Equipment installed in accordance with paragraphs (b)(1), (b)(2), or (b)(3) of this section shall be inspected as follows:

(i) Each drain using water seal controls shall be checked by visual or physical inspection initially and thereafter quarterly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls.

(ii) Each drain using a tightly sealed cap or plug shall be visually inspected initially and thereafter quarterly to ensure caps or plugs are in place and properly installed.

(iii) Each junction box shall be visually inspected initially and thereafter quarterly to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(iv) The unburied portion of each sewer line shall be visually inspected initially and thereafter quarterly for indication of cracks, gaps, or other problems that could result in benzene emissions.

(5) Except as provided in §61.350 of this subpart, when a broken seal, gap, crack or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

§61.347 Standards: Oil-water separators.

(a) Except as provided in §61.352 of this subpart, the owner or operator shall meet the following standards for each oil-water separator in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the oil-water separator to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the oil-water separator except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the oil-water separator is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(*1*) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(*2*) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h); and

(*3*) The pressure is monitored continuously to ensure that the pressure in the oil-water separator remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of §61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur between the cover and oil-water separator wall and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

§61.348 Standards: Treatment processes.

(a) Except as provided in paragraph (a)(5) of this section, the owner or operator shall treat the waste stream in accordance with the following requirements:

(1) The owner or operator shall design, install, operate, and maintain a treatment process that either:

(i) Removes benzene from the waste stream to a level less than 10 parts per million by weight (ppmw) on a flow-weighted annual average basis,

(2) Each treatment process complying with paragraphs (a)(1)(i) or (a)(1)(ii) of this section shall be designed and operated in accordance with the appropriate waste management unit standards specified in §§61.343 through 61.347 of this subpart. For example, if a treatment process is a tank, then the owner or operator shall comply with §61.343 of this subpart.

(3) For the purpose of complying with the requirements specified in paragraph (a)(1)(i) of this section, the intentional or unintentional reduction in the benzene concentration of a waste stream by dilution of the waste stream with other wastes or materials is not allowed.

(4) An owner or operator may aggregate or mix together individual waste streams to create a combined waste stream for the purpose of facilitating treatment of waste to comply with the requirements of paragraph (a)(1) of this section except as provided in paragraph (a)(5) of this section.

(5) If an owner or operator aggregates or mixes any combination of process wastewater, product tank drawdown, or landfill leachate subject to §61.342(c)(1) of this subpart together with other waste streams to create a combined waste stream for the purpose of facilitating management or treatment of waste in a wastewater treatment system, then the wastewater treatment system shall be operated in accordance with paragraph (b) of this section. These provisions apply to above-ground wastewater treatment systems as well as those that are at or below ground level.

(c) The owner and operator shall demonstrate that each treatment process or wastewater treatment system unit, except as provided in paragraph (d) of this section, achieves the appropriate conditions specified in paragraphs (a) or (b) of this section in accordance with the following requirements:

(1) Engineering calculations in accordance with requirements specified in §61.356(e) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in §61.355 of this subpart.

(e) Except as specified in paragraph (e)(3) of this section, if the treatment process or wastewater treatment system unit has any openings (e.g., access doors, hatches, etc.), all such openings shall be sealed (e.g., gasketed, latched, etc.) and kept closed at all times when waste is being treated, except during inspection and maintenance.

(1) Each seal, access door, and all other openings shall be checked by visual inspections initially and quarterly thereafter to ensure that no cracks or gaps occur and that openings are closed and gasketed properly.

(2) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

(3) If the cover and closed-vent system operate such that the treatment process and wastewater treatment system unit are maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the treatment process and wastewater treatment system unit remain below atmospheric pressure.

(f) Except for treatment processes complying with paragraph (d) of this section, the Administrator may request at any time an owner or operator demonstrate that a treatment process or wastewater treatment system unit meets the applicable requirements specified in paragraphs (a) or (b) of this section by conducting a performance test using the test methods and procedures as required in §61.355 of this subpart.

(g) The owner or operator of a treatment process or wastewater treatment system unit that is used to comply with the provisions of this section shall monitor the unit in accordance with the applicable requirements in §61.354 of this subpart.

§61.349 Standards: Closed-vent systems and control devices.

(a) For each closed-vent system and control device used to comply with standards in accordance with §§61.343 through 61.348 of this subpart, the owner or operator shall properly design, install, operate, and maintain the closed-vent system and control device in accordance with the following requirements:

(1) The closed-vent system shall:

(i) Be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(ii) Vent systems that contain any bypass line that could divert the vent stream away from a control device used to comply with the provisions of this subpart shall install, maintain, and operate according to the manufacturer's specifications a flow indicator that provides a record of vent stream flow away from the control device at least once every 15 minutes, except as provided in paragraph (a)(1)(ii)(B) of this section.

(A) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.

(B) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required.

(iii) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(iv) For each closed-vent system complying with paragraph (a) of this section, one or more devices which vent directly to the atmosphere may be used on the closed-vent system provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the closed-vent system resulting from malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(2) The control device shall be designed and operated in accordance with the following conditions:

(ii) A vapor recovery system (e.g., a carbon adsorption system or a condenser) shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(iv) A control device other than those described in paragraphs (a)(2) (i) through (iii) of this section may be used provided that the following conditions are met:

(A) The device shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(B) The owner or operator shall develop test data and design information that documents the control device will achieve an emission control efficiency of either 95 percent or greater for organic compounds or 98 percent or greater for benzene.

(C) The owner or operator shall identify:

(*1*) The critical operating parameters that affect the emission control performance of the device;

(*2*) The range of values of these operating parameters that ensure the emission control efficiency specified in paragraph (a)(2)(iv)(A) of this section is maintained during operation of the device; and

(*3*) How these operating parameters will be monitored to ensure the proper operation and maintenance of the device.

(D) The owner or operator shall submit the information and data specified in paragraphs (a)(2)(iv) (B) and (C) of this section to the Administrator prior to operation of the alternative control device.

(E) The Administrator will determine, based on the information submitted under paragraph (a)(2)(iv)(D) of this section, if the control device subject to paragraph (a)(2)(iv) of this section meets the requirements of §61.349. The control device subject to paragraph (a)(2)(iv) of this section may be operated prior to receiving approval from the Administrator. However, if the Administrator determines that the control device does not meet the requirements of §61.349, the facility may be subject to enforcement action beginning from the time the control device began operation.

(b) Each closed-vent system and control device used to comply with this subpart shall be operated at all times when waste is placed in the waste management unit vented to the control device except when maintenance or repair of the waste management unit cannot be completed without a shutdown of the control device.

(c) An owner and operator shall demonstrate that each control device, except for a flare, achieves the appropriate conditions specified in paragraph (a)(2) of this section by using one of the following methods:

(1) Engineering calculations in accordance with requirements specified in §61.356(f) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in §61.355 of this subpart.

(e) The Administrator may request at any time an owner or operator demonstrate that a control device meets the applicable conditions specified in paragraph (a)(2) of this section by conducting a performance test using the test methods and procedures as required in §61.355, and for control devices subject to paragraph (a)(2)(iv) of this section, the Administrator may specify alternative test methods and procedures, as appropriate.

(f) Each closed-vent system and control device shall be visually inspected initially and quarterly thereafter. The visual inspection shall include inspection of ductwork and piping and connections to covers and control devices for evidence of visible defects such as holes in ductwork or piping and loose connections.

(g) Except as provided in §61.350 of this subpart, if visible defects are observed during an inspection, or if other problems are identified, or if detectable emissions are measured, a first effort to repair the closed-vent system and control device shall be made as soon as practicable but no later than 5 calendar days after detection. Repair shall be completed no later than 15 calendar days after the emissions are detected or the visible defect is observed.

(h) The owner or operator of a control device that is used to comply with the provisions of this section shall monitor the control device in accordance with §61.354(c) of this subpart.

§61.350 Standards: Delay of repair.

(a) Delay of repair of facilities or units that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial facility or unit shutdown.

(b) Repair of such equipment shall occur before the end of the next facility or unit shutdown.

§61.351 Alternative standards for tanks.

(a) As an alternative to the standards for tanks specified in §61.343 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A fixed roof and internal floating roof meeting the requirements in 40 CFR 60.112b(a)(1);

(2) An external floating roof meeting the requirements of 40 CFR 60.112b (a)(2); or

(b) If an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions of §61.343 of this subpart applicable to the same facilities.

§61.352 Alternative standards for oil-water separators.

(a) As an alternative to the standards for oil-water separators specified in §61.347 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A floating roof meeting the requirements in 40 CFR 60.693–2(a); or

(b) For portions of the oil-water separator where it is infeasible to construct and operate a floating roof, such as over the weir mechanism, a fixed roof vented to a vapor control device that meets the requirements in §§61.347 and 61.349 of this subpart shall be installed and operated.

(c) Except as provided in paragraph (b) of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions in §61.347 of this subpart applicable to the same facilities.

§61.354 Monitoring of operations.

(a) Except for a treatment process or waste stream complying with §61.348(d), the owner or operator shall monitor each treatment process or wastewater treatment system unit to ensure the unit is properly operated and maintained by one of the following monitoring procedures:

(1) Measure the benzene concentration of the waste stream exiting the treatment process complying with §61.348(a)(1)(i) at least once per month by collecting and analyzing one or more samples using the procedures specified in §61.355(c)(3).

(2) Install, calibrate, operate, and maintain according to manufacturer's specifications equipment to continuously monitor and record a process parameter (or parameters) for the treatment process or wastewater treatment system unit that indicates proper system operation. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the unit is operating properly.

(c) An owner or operator subject to the requirements in §61.349 of this subpart shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device to continuously monitor the control device operation as specified in the following paragraphs, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator. The owner or operator shall inspect at

least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the control device is operating properly.

(d) For a carbon adsorption system that does not regenerate the carbon bed directly on site in the control device (e.g., a carbon canister), either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and either the organic concentration or the benzene concentration in the gas stream vented to the carbon adsorption system.

(f) Owners or operators using a closed-vent system that contains any bypass line that could divert a vent stream from a control device used to comply with the provisions of this subpart shall do the following:

(1) Visually inspect the bypass line valve at least once every month, checking the position of the valve and the condition of the car-seal or closure mechanism required under §61.349(a)(1)(ii) to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(2) Visually inspect the readings from each flow monitoring device required by §61.349(a)(1)(ii) at least once each operating day to check that vapors are being routed to the control device as required.

(g) Each owner or operator who uses a system for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device equipped with a continuous recorder to monitor the pressure in the unit to ensure that it is less than atmospheric pressure.

§61.355 Test methods, procedures, and compliance provisions.

(a) An owner or operator shall determine the total annual benzene quantity from facility waste by the following procedure:

(1) For each waste stream subject to this subpart having a flow-weighted annual average water content greater than 10 percent water, on a volume basis as total water, or is mixed with water or other wastes at any time and the resulting mixture has an annual average water content greater than 10 percent as specified in §61.342(a), the owner or operator shall:

(i) Determine the annual waste quantity for each waste stream using the procedures specified in paragraph (b) of this section.

(ii) Determine the flow-weighted annual average benzene concentration for each waste stream using the procedures specified in paragraph (c) of this section.

(iii) Calculate the annual benzene quantity for each waste stream by multiplying the annual waste quantity of the waste stream times the flow-weighted annual average benzene concentration.

(2) Total annual benzene quantity from facility waste is calculated by adding together the annual benzene quantity for each waste stream generated during the year and the annual benzene quantity for each process unit turnaround waste annualized according to paragraph (b)(4) of this section.

(3) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall comply with the requirements of §61.342 (c), (d), or (e).

(6) The benzene quantity in a waste stream that is generated less than one time per year, except as provided for process unit turnaround waste in paragraph (b)(4) of this section, shall be included in the determination of total annual benzene quantity from facility waste for the year in which the waste is

generated unless the waste stream is otherwise excluded from the determination of total annual benzene quantity from facility waste in accordance with paragraphs (a) through (c) of this section. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste, for purposes of determining the total annual benzene quantity from facility waste.

(b) For purposes of the calculation required by paragraph (a) of this section, an owner or operator shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in paragraphs (b) (1), (2), (3), and (4) of this section, by one of the methods given in paragraphs (b) (5) through (7) of this section.

(1) The determination of annual waste quantity for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(3) The determination of annual waste quantity for wastes that are received at hazardous waste treatment, storage, or disposal facilities from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.(4) The determination of annual waste quantity for each process unit turnaround waste generated only at 2 year or greater intervals, may be made by dividing the total quantity of waste generated during the most recent process unit turnaround by the time period (in the nearest tenth of a year) between the turnaround resulting in generation of the waste and the most recent preceding process turnaround for the unit. The resulting annual waste quantity shall be included in the calculation of the annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process turnaround. For estimates of total annual benzene quantity as specified in the 90-day report, required under §61.357(a)(1), the owner or operator shall estimate the waste quantity generated during the most recent turnaround, and the time period between turnarounds in accordance with good engineering practices. If the owner or operator chooses not to annualize process unit turnaround waste, as specified in this paragraph, then the process unit turnaround waste quantity shall be included in the calculation of the annual benzene quantity for the year in which the turnaround occurs.

(5) Select the highest annual quantity of waste managed from historical records representing the most recent 5 years of operation or, if the facility has been in service for less than 5 years but at least 1 year, from historical records representing the total operating life of the facility;

(6) Use the maximum design capacity of the waste management unit; or

(7) Use measurements that are representative of maximum waste generation rates.

(c) For the purposes of the calculation required by §§61.355(a) of this subpart, an owner or operator shall determine the flow-weighted annual average benzene concentration in a manner that meets the requirements given in paragraph (c)(1) of this section using either of the methods given in paragraphs (c)(2) and (c)(3) of this section.

(1) The determination of flow-weighted annual average benzene concentration shall meet all of the following criteria:

(i) The determination shall be made at the point of waste generation except for the specific cases given in paragraphs (c)(1)(i)(A) through (D) of this section.

(A) The determination for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(C) The determination for wastes that are received from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(D) The determination of flow-weighted annual average benzene concentration for process unit turnaround waste shall be made using either of the methods given in paragraph (c)(2) or (c)(3) of this section. The

resulting flow-weighted annual average benzene concentration shall be included in the calculation of annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process unit turnaround.

(ii) Volatilization of the benzene by exposure to air shall not be used in the determination to reduce the benzene concentration.

(iii) Mixing or diluting the waste stream with other wastes or other materials shall not be used in the determination—to reduce the benzene concentration.

(iv) The determination shall be made prior to any treatment of the waste that removes benzene, except as specified in paragraphs (c)(1)(i)(A) through (D) of this section.

(v) For wastes with multiple phases, the determination shall provide the weighted-average benzene concentration based on the benzene concentration in each phase of the waste and the relative proportion of the phases.

(2) *Knowledge of the waste.* The owner or operator shall provide sufficient information to document the flow-weighted annual average benzene concentration of each waste stream. Examples of information that could constitute knowledge include material balances, records of chemicals purchases, or previous test results provided the results are still relevant to the current waste stream conditions. If test data are used, then the owner or operator shall provide documentation describing the testing protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the flow-weighted annual average benzene concentration for the waste stream. When an owner or operator and the Administrator do not agree on determinations of the flow-weighted annual average benzene concentration based on knowledge of the waste, the procedures under paragraph (c)(3) of this section shall be used to resolve the disagreement.

(3) Measurements of the benzene concentration in the waste stream in accordance with the following procedures:

(i) Collect a minimum of three representative samples from each waste stream. Where feasible, samples shall be taken from an enclosed pipe prior to the waste being exposed to the atmosphere.

(ii) For waste in enclosed pipes, the following procedures shall be used:

(A) Samples shall be collected prior to the waste being exposed to the atmosphere in order to minimize the loss of benzene prior to sampling.

(B) A static mixer shall be installed in the process line or in a by-pass line unless the owner or operator demonstrates that installation of a static mixer in the line is not necessary to accurately determine the benzene concentration of the waste stream.

(C) The sampling tap shall be located within two pipe diameters of the static mixer outlet.

(D) Prior to the initiation of sampling, sample lines and cooling coil shall be purged with at least four volumes of waste.

(E) After purging, the sample flow shall be directed to a sample container and the tip of the sampling tube shall be kept below the surface of the waste during sampling to minimize contact with the atmosphere.

(F) Samples shall be collected at a flow rate such that the cooling coil is able to maintain a waste temperature less than 10 °C (50 °F).

(G) After filling, the sample container shall be capped immediately (within 5 seconds) to leave a minimum headspace in the container.

(H) The sample containers shall immediately be cooled and maintained at a temperature below 10 °C (50 °F) for transfer to the laboratory.

(iii) When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of benzene prior to sampling.

(iv) Each waste sample shall be analyzed using one of the following test methods for determining the benzene concentration in a waste stream:

(A) Method 8020, Aromatic Volatile Organics, in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW–846 (incorporation by reference as specified in §61.18 of this part);

(B) Method 8021, Volatile Organic Compounds in Water by Purge and Trap Capillary Column Gas Chromatography with Photoionization and Electrolytic Conductivity Detectors in Series in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW–846 (incorporation by reference as specified in §61.18 of this part);

(C) Method 8240, Gas Chromatography/Mass Spectrometry for Volatile Organics in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW–846 (incorporation by reference as specified in §61.18 of this part);

(D) Method 8260, Gas Chromatography/Mass Spectrometry for Volatile Organics: Capillary Column Technique in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW–846 (incorporation by reference as specified in §61.18 of this part);

(E) Method 602, Purgeable Aromatics, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA methods; or

(F) Method 624, Purgeables, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA method.

(v) The flow-weighted annual average benzene concentration shall be calculated by averaging the results of the sample analyses as follows:

$$\overline{C} = \frac{1}{Q_t} \times \sum_{i=1}^{n} (Q_i)(C_i)$$

Where:

C =Flow-weighted annual average benzene concentration for waste stream, ppmw.

Q_t=Total annual waste quantity for waste stream, kg/yr (lb/yr).

n=Number of waste samples (at least 3).

Q_i=Annual waste quantity for waste stream represented by C_i, kg/yr (lb/yr).

C_i=Measured concentration of benzene in waste sample i, ppmw.

(d) An owner or operator using performance tests to demonstrate compliance of a treatment process with §61.348 (a)(1)(i) shall measure the flow-weighted annual average benzene concentration of the waste stream exiting the treatment process by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown,

and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(e) An owner or operator using performance tests to demonstrate compliance of a treatment process with §61.348(a)(1)(ii) of this subpart shall determine the percent reduction of benzene in the waste stream on a mass basis by the following procedure:

(1) The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the treatment process (E_b) shall be determined by computing the product of the flow rate of the waste stream entering the treatment process, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene entering the treatment process is calculated as follows:

$$E_b = \frac{K}{n \times 10^6}\left[\sum_{i=1}^{n} V_i C_i\right]$$

Where:

E_b = Mass flow rate of benzene entering the treatment process, kg/hr (lb/hr).

K = Density of the waste stream, kg/m ^{3} (lb/ft ^{3}).

V_i = Average volume flow rate of waste entering the treatment process during each run i, m ^{3} /hr (ft ^{3} /hr).

C_i = Average concentration of benzene in the waste stream entering the treatment process during each run i, ppmw.

n = Number of runs.

10 ^{6} = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the treatment process (E_a) shall be determined by computing the product of the flow rate of the waste stream exiting the treatment process, as determined by the outlet flow meter or the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over the same 3-hour period at which the mass flow rate of benzene entering the treatment process is determined. The mass flow rate of benzene exiting the treatment process is calculated as follows:

$$E_a = \frac{K}{n \times 10^6}\left[\sum_{i=1}^{n} V_i C_i\right]$$

Where:

E_a = Mass flow rate of benzene exiting the treatment process, kg/hr (lb/hr).

K = Density of the waste stream, kg/m ^{3} (lb/ft ^{3}).

V_i = Average volume flow rate of waste exiting the treatment process during each run i, m ^{3} /hr (ft ^{3} /hr).

C_i = Average concentration of benzene in the waste stream exiting the treatment process during each run i, ppmw.

n = Number of runs.

10 ^{6} = Conversion factor for ppmw.

(h) An owner or operator shall test equipment for compliance with no detectable emissions as required in §§61.343 through 61.347, and §61.349 of this subpart in accordance with the following requirements:

(1) Monitoring shall comply with Method 21 from appendix A of 40 CFR part 60.

(2) The detection instrument shall meet the performance criteria of Method 21.

(3) The instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21.

(4) Calibration gases shall be:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(5) The background level shall be determined as set forth in Method 21.

(6) The instrument probe shall be traversed around all potential leak interfaces as close as possible to the interface as described in Method 21.

(7) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared to 500 ppm for determining compliance.

(i) An owner or operator using a performance test to demonstrate compliance of a control device with either the organic reduction efficiency requirement or the benzene reduction efficiency requirement specified under §61.349(a)(2) shall use the following procedures:

(1) The test shall be conducted under conditions that exist when the waste management unit vented to the control device is operating at the highest load or capacity level expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) Sampling sites shall be selected using Method 1 or 1A from appendix A of 40 CFR part 60, as appropriate.

(3) The mass flow rate of either the organics or benzene entering and exiting the control device shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected. Samples of the vent stream entering and exiting the control device shall be collected during the

same time period. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate;

(C) The organic concentration or the benzene concentration, as appropriate, in the vent stream entering and exiting the control shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of organics or benzene entering and exiting the control device during each run shall be calculated as follows:

$$M_{aj} = \frac{K_1 V_{aj}}{10^6}\left(\sum_{i=1}^{n} C_{ai} MW_i\right)$$

$$M_{bj} = \frac{K_1 V_{bj}}{10^6}\left(\sum_{i=1}^{n} C_{bi} MW_i\right)$$

M_{aj} = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

M_{bj} = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

V_{aj} = Volume of vent stream entering the control device during run j, at standard conditions, m^3 (ft^3).

V_{bj} = Volume of vent stream exiting the control device during run j, at standard conditions, m^3 (ft^3).

C_{ai} = Organic concentration of compound i or the benzene concentration measured in the vent stream entering the control device as determined by Method 18, ppm by volume on a dry basis.

C_{bi} = Organic concentration of compound i or the benzene concentration measured in the vent stream exiting the control device as determined by Method 18, ppm by volume on a dry basis.

MW_i = Molecular weight of organic compound i in the vent stream, or the molecular weight of benzene, kg/kg-mol (lb/lb-mole).

n = Number of organic compounds in the vent stream; if benzene reduction efficiency is being demonstrated, then n=1.

K_1 = Conversion factor for molar volume at standard conditions (293 K and 760 mm Hg (527 R and 14.7 psia))

= 0.0416 kg-mol/m^3 (0.00118 lb-mol/ft^3)

10^{-6}=Conversion factor for ppmv.

(iv) The mass flow rate of organics or benzene entering and exiting the control device shall be calculated as follows:

$$E_a = \left(\sum_{j=1}^{n} M_{aj}\right) / T$$

$$E_b = \left(\sum_{j=1}^{n} M_{bj} \right) / T$$

Where:

E_a = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

E_b = Mass flow rate of organics or benzene exiting the control device, kg/hr (lb/hr).

M_{aj} = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

M_{bj} = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(4) The organic reduction efficiency or the benzene reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_a - E_b}{E_a} \times 100$$

Where:

R = Total organic reduction of efficiency or benzene reduction efficiency for the control device, percent.

E_b = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

E_a = Mass flow rate of organic or benzene emitted from the control device, kg/hr (lb/hr).

(j) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by §61.342 (c)(3)(ii)(B) according to the provisions of paragraph (a) of this section, except that the procedures in paragraph (a) of this section shall also apply to wastes with a water content of 10 percent or less.

(k) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by §61.342(e)(2) by the following procedure:

(1) For each waste stream that is not controlled for air emissions in accordance with §61.343. 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the benzene quantity shall be determined as specified in paragraph (a) of this section, except that paragraph (b)(4) of this section shall not apply, i.e., the waste quantity for process unit turnaround waste is not annualized but shall be included in the determination of benzene quantity for the year in which the waste is generated for the purposes of the calculation required by §61.342(e)(2).

(2) For each waste stream that is controlled for air emissions in accordance with §61.343. 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the determination of annual waste quantity and flow-weighted annual average benzene concentration shall be made at the first applicable location as described in paragraphs (k)(2)(i), (k)(2)(ii), and (k)(2)(iii) of this section and prior to any reduction of benzene concentration through volatilization of the benzene, using the methods given in (k)(2)(iv) and (k)(2)(v) of this section.

(i) Where the waste stream enters the first waste management unit not complying with §§61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a) that are applicable to the waste management unit,

(ii) For each waste stream that is managed or treated only in compliance with §§61.343 through 61.348(a) up to the point of final direct discharge from the facility, the determination of benzene quantity shall be prior to any reduction of benzene concentration through volatilization of the benzene, or

(iii) For wastes managed in units controlled for air emissions in accordance with §§61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a), and then transferred offsite, facilities shall use the first applicable offsite location as described in paragraphs (k)(2)(i) and (k)(2)(ii) of this section if they have documentation from the offsite facility of the benzene quantity at this location. Facilities without this documentation for offsite wastes shall use the benzene quantity determined at the point where the transferred waste leaves the facility.

(iv) Annual waste quantity shall be determined using the procedures in paragraphs (b)(5), (6), or (7) of this section, and

(v) The flow-weighted annual average benzene concentration shall be determined using the procedures in paragraphs (c)(2) or (3) of this section.

(3) The benzene quantity in a waste stream that is generated less than one time per year, including process unit turnaround waste, shall be included in the determination of benzene quantity as determined in paragraph (k)(6) of this section for the year in which the waste is generated. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste for purposes of determining benzene quantity as determined in paragraph (k)(6) of this section.

(4) The benzene in waste entering an enhanced biodegradation unit, as defined in §61.348(b)(2)(ii)(B), shall not be included in the determination of benzene quantity, determined in paragraph (k)(6) of this section, if the following conditions are met:

(i) The benzene concentration for each waste stream entering the enhanced biodegradation unit is less than 10 ppmw on a flow-weighted annual average basis, and

(ii) All prior waste management units managing the waste comply with §§61.343, 61.344, 61.345, 61.346, 61.347 and 61.348(a).

(5) The benzene quantity for each waste stream in paragraph (k)(2) of this section shall be determined by multiplying the annual waste quantity of each waste stream times its flow-weighted annual average benzene concentration.

(6) The total benzene quantity for the purposes of the calculation required by §61.342(e)(2) shall be determined by adding together the benzene quantities determined in paragraphs (k)(1) and (k)(5) of this section for each applicable waste stream.

(7) If the benzene quantity determined in paragraph (6) of this section exceeds 6.0 Mg/yr (6.6 ton/yr) only because of multiple counting of the benzene quantity for a waste stream, the owner or operator may use the following procedures for the purposes of the calculation required by §61.342(e)(2):

(i) Determine which waste management units are involved in the multiple counting of benzene;

(ii) Determine the quantity of benzene that is emitted, recovered, or removed from the affected units identified in paragraph (k)(7)(i) of this section, or destroyed in the units if applicable, using either direct measurements or the best available estimation techniques developed or approved by the Administrator.

(iii) Adjust the benzene quantity to eliminate the multiple counting of benzene based on the results from paragraph (k)(7)(ii) of this section and determine the total benzene quantity for the purposes of the calculation required by §61.342(e)(2).

(iv) Submit in the annual report required under §61.357(a) a description of the methods used and the resulting calculations for the alternative procedure under paragraph (k)(7) of this section, the benzene

quantity determination from paragraph (k)(6) of this section, and the adjusted benzene quantity determination from paragraph (k)(7)(iii) of this section.

§61.356 Recordkeeping requirements.

(a) Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. Each record shall be maintained in a readily accessible location at the facility site for a period not less than two years from the date the information is recorded unless otherwise specified.

(b) Each owner or operator shall maintain records that identify each waste stream at the facility subject to this subpart, and indicate whether or not the waste stream is controlled for benzene emissions in accordance with this subpart. In addition the owner or operator shall maintain the following records:

(1) For each waste stream not controlled for benzene emissions in accordance with this subpart, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(4) For each facility where waste streams are controlled for benzene emissions in accordance with §61.342(e), the records shall include for each waste stream all measurements, including the locations of the measurements, calculations, and other documentation used to determine that the total benzene quantity does not exceed 6.0 Mg/yr (6.6 ton/yr).

(5) For each facility where the annual waste quantity for process unit turnaround waste is determined in accordance with §61.355(b)(5), the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnarounds, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste, the water content of each process unit turnaround waste, the annual waste quantity determined in accordance with §61.355(b)(5), the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with §61.355(a)(1)(iii) of this section.

(c) An owner or operator transferring waste off-site to another facility for treatment in accordance with §61.342(f) shall maintain documentation for each offsite waste shipment that includes the following information: Date waste is shipped offsite, quantity of waste shipped offsite, name and address of the facility receiving the waste, and a copy of the notice sent with the waste shipment.

(d) An owner or operator using control equipment in accordance with §§61.343 through 61.347 shall maintain engineering design documentation for all control equipment that is installed on the waste management unit. The documentation shall be retained for the life of the control equipment. If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section.

(e) An owner or operator using a treatment process or wastewater treatment system unit in accordance with §61.348 of this subpart shall maintain the following records. The documentation shall be retained for the life of the unit.

(1) A statement signed and dated by the owner or operator certifying that the unit is designed to operate at the documented performance level when the waste stream entering the unit is at the highest waste stream flow rate and benzene content expected to occur.

(2) If engineering calculations are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain the complete design analysis for the unit. The design analysis shall include for example the following information: Design specifications, drawings, schematics, piping and instrumentation diagrams, and other documentation necessary to demonstrate the unit performance.

(3) If performance tests are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain all test information necessary to demonstrate the unit performance.

(i) A description of the unit including the following information: type of treatment process; manufacturer name and model number; and for each waste stream entering and exiting the unit, the waste stream type (e.g., process wastewater, sludge, slurry, etc.), and the design flow rate and benzene content.

(ii) Documentation describing the test protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the unit performance. The description of the test protocol shall include the following information: sampling locations, sampling method, sampling frequency, and analytical procedures used for sample analysis.

(iii) Records of unit operating conditions during each test run including all key process parameters.

(iv) All test results.

(4) If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section.

(f) An owner or operator using a closed-vent system and control device in accordance with §61.349 of this subpart shall maintain the following records. The documentation shall be retained for the life of the control device.

(1) A statement signed and dated by the owner or operator certifying that the closed-vent system and control device is designed to operate at the documented performance level when the waste management unit vented to the control device is or would be operating at the highest load or capacity expected to occur.

(2) If engineering calculations are used to determine control device performance in accordance with §61.349(c), then a design analysis for the control device that includes for example:

(i) Specifications, drawings, schematics, and piping and instrumentation diagrams prepared by the owner or operator, or the control device manufacturer or vendor that describe the control device design based on acceptable engineering texts. The design analysis shall address the following vent stream characteristics and control device operating parameters:

(G) For a carbon adsorption system that does not regenerate the carbon bed directly on-site in the control device, such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device subject to the requirements of §61.349(a)(2)(iv), the design analysis shall consider the vent stream composition, constituent concentration, and flow rate. The design analysis shall also include all of the information submitted under §61.349 (a)(2)(iv).

(g) An owner or operator shall maintain a record for each visual inspection required by §§61.343 through 61.347 of this subpart that identifies a problem (such as a broken seal, gap or other problem) which could result in benzene emissions. The record shall include the date of the inspection, waste management unit

and control equipment location where the problem is identified, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(h) An owner or operator shall maintain a record for each test of no detectable emissions required by §§61.343 through 61.347 and §61.349 of this subpart. The record shall include the following information: date the test is performed, background level measured during test, and maximum concentration indicated by the instrument reading measured for each potential leak interface. If detectable emissions are measured at a leak interface, then the record shall also include the waste management unit, control equipment, and leak interface location where detectable emissions were measured, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(i) For each treatment process and wastewater treatment system unit operated to comply with §61.348, the owner or operator shall maintain documentation that includes the following information regarding the unit operation:

(1) Dates of startup and shutdown of the unit.

(2) If measurements of waste stream benzene concentration are performed in accordance with §61.354(a)(1) of this subpart, the owner or operator shall maintain records that include date each test is performed and all test results.

(3) If a process parameter is continuously monitored in accordance with §61.354(a)(2) of this subpart, the owner or operator shall maintain records that include a description of the operating parameter (or parameters) to be monitored to ensure that the unit will be operated in conformance with these standards and the unit's design specifications, and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the unit.

(5) Periods when the unit is not operated as designed.

(j) For each control device, the owner or operator shall maintain documentation that includes the following information regarding the control device operation:

(1) Dates of startup and shutdown of the closed-vent system and control device.

(2) A description of the operating parameter (or parameters) to be monitored to ensure that the control device will be operated in conformance with these standards and the control device's design specifications and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the control device.

(3) Periods when the closed-vent system and control device are not operated as designed including all periods and the duration when:

(i) Any valve car-seal or closure mechanism required under §61.349(a)(1)(ii) is broken or the by-pass line valve position has changed.

(ii) The flow monitoring devices required under §61.349(a)(1)(ii) indicate that vapors are not routed to the control device as required.

(9) If a carbon adsorber is used, then the owner or operator shall maintain records from the monitoring device of the concentration of organics or the concentration of benzene in the control device outlet gas stream. If the concentration of organics or the concentration of benzene in the control device outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of benzene in the exhaust stream is more than 20 percent greater than the design value. If the carbon bed regeneration interval is monitored, then the owner or operator shall record each occurrence when the vent stream continues to flow through the control device beyond the predetermined carbon bed regeneration time.

(10) If a carbon adsorber that is not regenerated directly on site in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time then the existing carbon in the control device is replaced with fresh carbon.

(11) If an alternative operational or process parameter is monitored for a control device, as allowed in §61.354(e) of this subpart, then the owner or operator shall maintain records of the continuously monitored parameter, including periods when the device is not operated as designed.

(12) If a control device subject to the requirements of §61.349(a)(2)(iv) is used, then the owner or operator shall maintain records of the parameters that are monitored and each occurrence when the parameters monitored are outside the range of values specified in §61.349(a)(2)(iv)(C), or other records as specified by the Administrator.

(k) An owner or operator who elects to install and operate the control equipment in §61.351 of this subpart shall comply with the recordkeeping requirements in 40 CFR 60.115b.

(l) An owner or operator who elects to install and operate the control equipment in §61.352 of this subpart shall maintain records of the following:

(1) The date, location, and corrective action for each visual inspection required by 40 CFR 60.693–2(a)(5), during which a broken seal, gap, or other problem is identified that could result in benzene emissions.

(2) Results of the seal gap measurements required by 40 CFR 60.693–2(a).

(m) If a system is used for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air, then the owner or operator shall maintain records of the monitoring device and records of all periods during which the pressure in the unit is operated at a pressure that is equal to or greater than atmospheric pressure.

§61.357 Reporting requirements.

(a) Each owner or operator of a chemical plant, petroleum refinery, coke by-product recovery plant, and any facility managing wastes from these industries shall submit to the Administrator within 90 days after January 7, 1993, or by the initial startup for a new source with an initial startup after the effective date, a report that summarizes the regulatory status of each waste stream subject to §61.342 and is determined by the procedures specified in §61.355(c) to contain benzene. Each owner or operator subject to this subpart who has no benzene onsite in wastes, products, by-products, or intermediates shall submit an initial report that is a statement to this effect. For all other owners or operators subject to this subpart, the report shall include the following information:

(1) Total annual benzene quantity from facility waste determined in accordance with §61.355(a) of this subpart.

(2) A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions in accordance with the requirements of this subpart.

(3) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart the following information shall be added to the table:

(i) Whether or not the water content of the waste stream is greater than 10 percent;

(ii) Whether or not the waste stream is a process wastewater stream, product tank drawdown, or landfill leachate;

(iii) Annual waste quantity for the waste stream;

(iv) Range of benzene concentrations for the waste stream;

(v) Annual average flow-weighted benzene concentration for the waste stream; and

(vi) Annual benzene quantity for the waste stream.

(4) The information required in paragraphs (a) (1), (2), and (3) of this section should represent the waste stream characteristics based on current configuration and operating conditions. An owner or operator only needs to list in the report those waste streams that contact materials containing benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in §61.10(a).

(d) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall submit to the Administrator the following reports:

(1) Within 90 days after January 7, 1993, unless a waiver of compliance under §61.11 of this part is granted, or by the date of initial startup for a new source with an initial startup after the effective date, a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests have been carried out in accordance with this subpart. If a waiver of compliance is granted under §61.11, the certification of equipment necessary to comply with these standards shall be submitted by the date the waiver of compliance expires.

(2) Beginning on the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. If the information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in the following year, the owner or operator may submit a statement to that effect.

(5) If an owner or operator elects to comply with the alternative requirements of §61.342(e), then the report required by paragraph (d)(2) of this section shall include a table presenting the following information for each waste stream:

(i) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information for the waste stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity;

(ii) For each waste stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information for the waste stream as determined at the applicable location described in §61.355(k)(2): Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(6) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit quarterly to the Administrator a certification that all of the required inspections have been carried out in accordance with the requirements of this subpart.

(7) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit a report quarterly to the Administrator that includes:

(i) If a treatment process or wastewater treatment system unit is monitored in accordance with §61.354(a)(1) of this subpart, then each period of operation during which the concentration of benzene in the monitored waste stream exiting the unit is equal to or greater than 10 ppmw.

(iv) For a control device monitored in accordance with §61.354(c) of this subpart, each period of operation monitored during which any of the following conditions occur, as applicable to the control device:

(I) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly on site in the control device is not replaced at the predetermined interval specified in §61.354(c) of this subpart.

(J) Each 3-hour period of operation during which the parameters monitored are outside the range of values specified in §61.349(a)(2)(iv)(C), or any other periods specified by the Administrator for a control device subject to the requirements of §61.349(a)(2)(iv).

(v) For a cover and closed-vent system monitored in accordance with §61.354(g), the owner or operator shall submit a report quarterly to the Administrator that identifies any period in which the pressure in the waste management unit is equal to or greater than atmospheric pressure.

(8) Beginning one year after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Administrator a report that summarizes all inspections required by §§61.342 through 61.354 during which detectable emissions are measured or a problem (such as a broken seal, gap or other problem) that could result in benzone emissions is identified, including information about the repairs or corrective action taken.

(e) An owner or operator electing to comply with the provisions of §§61.351 or 61.352 of this subpart shall notify the Administrator of the alternative standard selected in the report required under §61.07 or §61.10 of this part.

(f) An owner or operator who elects to install and operate the control equipment in §61.351 of this subpart shall comply with the reporting requirements in 40 CFR 60.115b.

(g) An owner or operator who elects to install and operate the control equipment in §61.352 of this subpart shall submit initial and quarterly reports that identify all seal gap measurements, as required in 40 CFR 60.693–2(a), that are outside the prescribed limits.

SECTION E.4 40 CFR Part 60, Subpart VV - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

E.4.1 NSPS Subpart VV Requirements [40 CFR Part 60, Subpart VV] [326 IAC 12]

Pursuant to 40 CFR 60.590 and 63.648, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart VV for all affected pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves and lines, valves, connectors, and closed vent systems as specified below:

Subpart VV—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

§60.482-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§60.482–1 through 60.482–10 or §60.480(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§60.482–1 to 60.482–10 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485.

(d) Equipment that is in vacuum service is excluded from the requirements of §§60.482–2 to 60.482–10 if it is identified as required in §60.486(e)(5).

§ 60.482-2 Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485(b), except as provided in §60.482–1(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

(b)(1) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(2) If there are indications of liquids dripping from the pump seal, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a), *Provided* the following requirements are met:

(1) Each dual mechanical seal system is—

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipment with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482–10; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm, and

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(6)(i) If there are indications of liquids dripping from the pump seal or the sensor indicates failure of the seal system, the barrier fluid system, or both based on the criterion determined in paragraph (d)(5)(ii), a leak is detected.

(ii) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9.

(iii) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) Any pump that is designated, as described in §60.486(e)(1) and (2), for no detectable emission, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing,

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in §60.485(c), and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of §60.482–10, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in §60.486(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

§ 60.482-3 Standards: Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in §60.482–1(c) and paragraph (h) and (i) of this section.

(b) Each compressor seal system as required in paragraph (a) shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482–10; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2), a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of §60.482–10, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in §60.486(e) (1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a)–(h) if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in §60.485(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of §60.14 or §60.15 is exempt from §60.482(a), (b), (c), (d), (e), and (h), provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

§ 60.482-4 Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in §60.485(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as

soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in §60.482–9.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in §60.485(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482–10 is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in §60.482–9.

§ 60.482-5 Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed-purged, closed-loop, or closed-vent system, except as provided in §60.482–1(c). Gases displaced during filling of the sample container are not required to be collected or captured.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section:

(1) Return the purged process fluid directly to the process line; or

(2) Collect and recycle the purged process fluid to a process; or

(3) Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of §60.482–10; or

(4) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(i) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to, and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(ii) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266; or

(iii) A facility permitted, licensed, or registered by a State to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261.

(c) In situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

§ 60.482-6 Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482–1(c).

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b) and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

§ 60.482-7 Standards: Valves in gas/vapor service and in light liquid service.

(a) Each valve shall be monitored monthly to detect leaks by the methods specified in §60.485(b) and shall comply with paragraphs (b) through (e), except as provided in paragraphs (f), (g), and (h), §60.483–1, 2, and §60.482–1(c).

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §60.482–9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in §60.486(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in §60.486(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a), and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in §60.486(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either becomes an affected facility through §60.14 or §60.15 or the owner or operator designates less than 3.0 percent of the total number of valves as difficult-to-monitor, and

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

§ 60.482-8 Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors.

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §60.482–7(e).

§ 60.482-9 Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482–10.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

§ 60.482-10 Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (f)(2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (f)(1)(ii) of this section:

(i) Conduct an initial inspection according to the procedures in §60.485(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(g) Leaks, as indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (j)(2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (k)(3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (l)(5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in §60.486(c).

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

§ 60.485 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the standards in §§60.482, 60.483, and 60.484 as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.

(c) The owner or operator shall determine compliance with the no detectable emission standards in §§60.482–2(e), 60.482–3(i), 60.482–4, 60.482–7(f), and 60.482–10(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260–73, 91, or 96, E168–67, 77, or 92, E169–63, 77, or 93 (incorporated by reference—see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d) (1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that an equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

V_{max} = Maximum permitted velocity, m/sec (ft/sec)

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units)

= 28.56 ft/sec (English units)

K_2 = 0.7084 m^4 /(MJ-sec) (metric units)

= 0.087 ft^4 /(Btu-sec) (English units)

(4) The net heating value (HT) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K\sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740 × 10^7 (g-mole)(MJ)/ (ppm-scm-kcal) (metric units)

= 4.674 × 10^8 [(g-mole)(Btu)/(ppm-scf-kcal)] (English units)

C_i = Concentration of sample component "i," ppm

H_i = net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole

(5) Method 18 and ASTM D2504–67, 77, or 88 (Reapproved 1993) (incorporated by reference—see §60.17) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382–76 or 88 or D4809–95 (incorporated by reference—see §60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

§ 60.486 Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(b) When each leak is detected as specified in §§60.482–2, 60.482–3, 60.482–7, 60.482–8, and 60.483–2, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482–7(c) and no leak has been detected during those 2 months.

(3) The identification on equipment except on a valve, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§60.482–2, 60.482–3, 60.482–7, 60.482–8, and 60.483–2, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) “Above 10,000” if the maximum instrument reading measured by the methods specified in §60.485(a) after each repair attempt is equal to or greater than 10,000 ppm.

(5) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in §60.482–10 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in §60.482–10(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§60.482–2, 60.482–3, 60.482–4, and 60.482–5 are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482–2, 60.482–3, 60.482–4, and 60.482–5.

(e) The following information pertaining to all equipment subject to the requirements in §§60.482–1 to 60.482–10 shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482–2(e), 60.482–3(i) and 60.482–7(f).

(ii) The designation of equipment as subject to the requirements of §60.482–2(e), §60.482–3(i), or §60.482–7(f) shall be signed by the owner or operator.

(3) A list of equipment identification numbers for pressure relief devices required to comply with §60.482–4.

(4)(i) The dates of each compliance test as required in §§60.482–2(e), 60.482–3(i), 60.482–4, and 60.482–7(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(f) The following information pertaining to all valves subject to the requirements of §60.482–7(g) and (h) and to all pumps subject to the requirements of §60.482–2(g) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with §60.483–2:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§60.482–2(d)(5) and 60.482–3(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of §60.7 (b) and (d) do not apply to affected facilities subject to this subpart.

§ 60.487 Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning six months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of §60.482–7, excluding those valves designated for no detectable emissions under the provisions of §60.482–7(f).

(3) Number of pumps subject to the requirements of §60.482–2, excluding those pumps designated for no detectable emissions under the provisions of §60.482–2(e) and those pumps complying with §60.482–2(f).

(4) Number of compressors subject to the requirements of §60.482–3, excluding those compressors designated for no detectable emissions under the provisions of §60.482–3(i) and those compressors complying with §60.482–3(h).

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in §60.482(7)(b) or §60.483–2,

(ii) Number of valves for which leaks were not repaired as required in §60.482–7(d)(1),

(iii) Number of pumps for which leaks were detected as described in §60.482–2(b) and (d)(6)(i),

(iv) Number of pumps for which leaks were not repaired as required in §60.482–2(c)(1) and (d)(6)(ii),

(v) Number of compressors for which leaks were detected as described in §60.482–3(f),

(vi) Number of compressors for which leaks were not repaired as required in §60.482–3(g)(1), and

(vii) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.

§ 60.488 Reconstruction.

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the “fixed capital cost of the new components” or the “fixed capital costs that would be required to construct a comparable new facility” under §60.15: pump seals, nuts and bolts, rupture disks, and packings.

(b) Under §60.15, the “fixed capital cost of new components” includes the fixed capital cost of all depreciable components (except components specified in §60.488 (a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the “Applicability and designation of affected facility” section of the appropriate subpart.) For purposes of this paragraph, “commenced” means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

E.4.2 One Time Deadlines Relating to NSPS Subpart VV

The Permittee shall comply with the following requirements by the dates listed below:

Requirement	Rule Citation	Affected Facility	Deadline
Notification of the date of construction commencement	40 CFR 60.7(a)(1)	Pumps, Valves, and Connectors.	No later than 30 days after commencement of construction

Requirement	Rule Citation	Affected Facility	Deadline
Complete Performance Tests	40 CFR 60.8	Pumps, Valves, and Connectors	Within 60-days after achieving maximum production rate but not later than 180-days after initial startup
Notification of Schedule of Initial Performance Tests	40 CFR 60.487(e)	Pumps, Valves, and Connectors	At least 30-days prior to initial performance tests
Notification of initial startup	40 CFR 60.7(a)(3)	Pumps, Valves, and Connectors	Within 15 days of startup
Demonstrate Initial Compliance	40 CFR 60.482-1(a)	Pumps, Valves, and Connectors	Within 180-days of initial startup
Initial Semiannual Report	40 CFR 60.487(a)	Pumps, Valves, and Connectors	Six months after the initial startup date or in the next semi-annual report submitted for the existing equipment at the refinery after startup of the new equipment

SECTION E.5 40 CFR Part 61, Subpart J – National Emission Standards for Equipment Leaks (Fugitive Emission Sources) of Benzene And 40 CFR Part 61 Subpart V – National Emission Standards for Equipment Leaks (Fugitive Emission Sources)

E.5.1 General Provisions Relating to NESHAPs [326 IAC 14-1] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR Part 61.1(c), the Permittee shall comply with the provisions of 40 CFR Part 61, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 14-1, for each pump, pressure relief device, sampling connection system, open-ended valve, open-ended line, and valve that are operating in benzene service, except when otherwise specified in 40 CFR Part 61, Subparts J and V.

E.5.2 NESHAP Requirements for 40 CFR Part 61, Subpart J [326 IAC 14]

Pursuant to 40 CFR 61.110(a), the Permittee shall comply with the provisions of 40 CFR Part 61, Subpart J, which are incorporated by reference as 326 IAC 14, for the emission units identified in Condition E.5.1, as specified below:

Subpart J—National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene

§61.110 Applicability and designation of sources.

(a) The provisions of this subpart apply to each of the following sources that are intended to operate in benzene service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by this subpart.

(c)(1) If an owner or operator applies for one of the exemptions in this paragraph, then the owner or operator shall maintain records as required in §61.246(i).

(2) Any equipment in benzene service that is located at a plant site designed to produce or use less than 1,000 megagrams (1,102 tons) of benzene per year is exempt from the requirements of §61.112.

(3) Any process unit (defined in §61.241) that has no equipment in benzene service is exempt from the requirements of §61.112.

(d) While the provisions of this subpart are effective, a source to which this subpart applies that is also subject to the provisions of 40 CFR part 60 only will be required to comply with the provisions of this subpart.

§61.112 Standards.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of subpart V of this part.

E.5.3 NESHAP Requirements for 40 CFR Part 61, Subpart V [326 IAC 14]

Pursuant to 40 CFR 61.112(a), the Permittee shall comply with the provisions of 40 CFR Part 61, Subpart V, which are incorporated by reference as 326 IAC 14, for the emission units identified in Condition E.5.1, as specified below:

Subpart V—National Emission Standard for Equipment Leaks (Fugitive Emission Sources)

§61.240 Applicability and designation of sources.

(a) The provisions of this subpart apply to each of the following sources that are intended to operate in volatile hazardous air pollutant (VHAP) service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by this subpart.

(b) The provisions of this subpart apply to the sources listed in paragraph (a) after the date of promulgation of a specific subpart in part 61.

(c) While the provisions of this subpart are effective, a source to which this subpart applies that is also subject to the provisions of 40 CFR part 60 only will be required to comply with the provisions of this subpart.

§61.242-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§61.242–1 to 61.242–11 for each new and existing source as required in 40 CFR 61.05, except as provided in §§61.243 and 61.244.

(b) Compliance with this subpart will be determined by review of records, review of performance test results, and inspection using the methods and procedures specified in §61.245.

(c)(1) An owner or operator may request a determination of alternative means of emission limitation to the requirements of §§61.242–2, 61.242–3, 61.242–5, 61.242–6, 61.242–7, 61.242–8, 61.242–9 and 61.242–11 as provided in §61.244.

(2) If the Administrator makes a determination that a means of emission limitation is at least a permissible alternative to the requirements of §61.242–2, 61.242–3, 61.242–5, 61.242–6, 61.242–7, 61.242–8, 61.242–9 or 61.242–11, an owner or operator shall comply with the requirements of that determination.

(d) Each piece of equipment to which this subpart applies shall be marked in such a manner that it can be distinguished readily from other pieces of equipment.

§61.242-11 Standards: Closed-vent systems and control devices.

(a) Owners or operators of closed-vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section, except as provided in §61.242–1(c).

(c) Enclosed combustion devices shall be designed and operated to reduce the VHAP emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent, or to provide a minimum residence time of 0.50 seconds at a minimum temperature of 760 °C.

(d) Flares shall used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices that are used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their design.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraph (f)(1) or (2) of this section, as applicable.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the following requirements:

(i) Conduct an initial inspection according to the procedures in §61.245(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(g) Leaks, as indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown, or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe-to-inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (2) of this section if they comply with the following requirements:

(1) The owner or operator determines that the equipment is unsafe-to-inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraph (f)(1)(i) or (2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult-to-inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (2) of this section if they comply with the following requirements:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the following information:

(1) Identification of all parts of the closed vent system that are designated as unsafe-to-inspect, an explanation of why the equipment is unsafe-to-inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult-to-inspect, an explanation of why the equipment is difficult-to-inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in §61.246(c).

(4) For each inspection conducted in accordance with §61.245(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

§61.245 Test methods and procedures.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the test methods and procedures requirements provided in this section.

(b) Monitoring, as required in §§61.242, 61.243, 61.244, and 61.135, shall comply with the following requirements:

(1) Monitoring shall comply with Method 21 of appendix A of 40 CFR part 60.

(2) The detection instrument shall meet the performance criteria of Method 21.

(3) The instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21.

(4) Calibration gases shall be:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(5) The instrument probe shall be traversed around all potential leak interfaces as close to the interface as possible as described in Method 21.

(e)(1) Method 22 of appendix A of 40 CFR part 60 shall be used to determine compliance of flares with the visible emission provisions of this subpart.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K\sum_{i=1}^{n} C_i H_i$$

Where:

H_T = Net heating value of the sample, MJ/scm (BTU/scf); where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg (77 °F and 14.7 psi), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F).

K = conversion constant, 1.740×10^{7} (g-mole) (MJ)/(ppm-scm-kcal) (metric units); or 4.674×10^{8} ((g-mole) (Btu)/(ppm-scf-kcal)) (English units)

Ci = Concentration of sample component “i” in ppm, as measured by Method 18 of appendix A to 40 CFR part 60 and ASTM D2504–67, 77, or 88 (Reapproved 1993) (incorporated by reference as specified in §61.18).

H_i = net heat of combustion of sample component “i” at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole. The heats of combustion may be determined using ASTM D2382–76 or 88 or D4809–95 (incorporated by reference as specified in §61.18) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Method 2, 2A, 2C, or 2D, as appropriate, by the unobstructed (free) cross section area of the flare tip.

(5) The maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

V_{max} = Maximum permitted velocity, m/sec (ft/sec).

H_T = Net heating value of the gas being combusted, as determined in paragraph (e)(3) of this section, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units)

= 28.56 ft/sec (English units)

K_2 = 0.7084 m^4 /(MJ-sec) (metric units)

= 0.087 ft^4 /(Btu-sec) (English units)

§61.246 Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one process unit subject to the provisions of this subpart may comply with the recordkeeping requirements for these process units in one recordkeeping system if the system identifies each record by each process unit.

(d) The following information pertaining to the design requirements for closed-vent systems and control devices described in §61.242–11 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in §61.242–11(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed-vent systems and control devices required in §§61.242–2, 61.242–3, 61.242–4, 61.242–5 and 61.242–9 are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed-vent systems and control devices required in §§61.242–2, 61.242–3, 61.242–4, 61.242–5 and 61.242–9.

(e) The following information pertaining to all equipment to which a standard applies shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment (except welded fittings) subject to the requirements of this subpart.

§61.247 Reporting requirements.

(a)(1) An owner or operator of any piece of equipment to which this subpart applies shall submit a statement in writing notifying the Administrator that the requirements of §§61.242, 61.245, 61.246, and 61.247 are being implemented.

(2) In the case of an existing source or a new source which has an initial startup date preceding the effective date, the statement is to be submitted within 90 days of the effective date, unless a waiver of compliance is granted under §61.11, along with the information required under §61.10. If a waiver of compliance is granted, the statement is to be submitted on a date scheduled by the Administrator.

(3) In the case of new sources which did not have an initial startup date preceding December 14, 2000, the statement required under paragraph (a)(1) of this section shall be submitted with the application for approval of construction, as described in §61.07.

(4) For owners and operators complying with 40 CFR part 65, subpart C or F, the statement required under paragraph (a)(1) of this section shall notify the Administrator that the requirements of 40 CFR part 65, subpart C or F, are being implemented.

(5) The statement is to contain the following information for each source:

(i) Equipment identification number and process unit identification.

(ii) Type of equipment (for example, a pump or pipeline valve).

(iii) Percent by weight VHAP in the fluid at the equipment.

(iv) Process fluid state at the equipment (gas/vapor or liquid).

(v) Method of compliance with the standard (for example, “monthly leak detection and repair” or “equipped with dual mechanical seals”).

(b) A report shall be submitted to the Administrator semiannually starting 6 months after the initial report required in paragraph (a) of this section, that includes the following information:

(1) Process unit identification.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (a) if changes have occurred since the initial report or subsequent revisions to the initial report.

Note: Compliance with the requirements of §61.10(c) is not required for revisions documented under this paragraph.

(c) In the first report submitted as required in paragraph (a) of this section, the report shall include a reporting schedule stating the months that semiannual reports shall be submitted. Subsequent reports shall be submitted according to that schedule, unless a revised schedule has been submitted in a previous semiannual report.

(e) An application for approval of construction or modification, §§61.05(a) and 61.07, will not be required if—

(1) The new source complies with the standard, §61.242;

(2) The new source is not part of the construction of a process unit; and

(3) In the next semiannual report required by paragraph (b) of this section, the information in paragraph (a)(5) of this section is reported.

SECTION E.6 40 CFR Part 60, Subpart QQQ - Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems

E.6.1 General Provisions Relating to NSPS Subpart QQQ [326 IAC 12-1] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR Part 60.1(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the affected emission units at this source, except when otherwise specified in 40 CFR Part 60, Subpart QQQ.

E.6.2 NSPS Subpart QQQ Requirements [40 CFR Part 60, Subpart QQQ] [326 IAC 12]

Pursuant to 40 CFR 60.690(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart QQQ, which are incorporated by reference as 326 IAC 12, for the refinery wastewater systems as specified below:

Subpart QQQ—Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems

§60.690 Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities located in petroleum refineries for which construction, modification, or reconstruction is commenced after May 4, 1987.

(2) An individual drain system is a separate affected facility.

(3) An oil-water separator is a separate affected facility.

(4) An aggregate facility is a separate affected facility.

(b) Notwithstanding the provisions of 40 CFR 60.14(e)(2), the construction or installation of a new individual drain system shall constitute a modification to an affected facility described in §60.690(a)(4). For purposes of this paragraph, a new individual drain system shall be limited to all process drains and the first common junction box.

§60.692-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §§60.692–1 to 60.692–5 and with §§60.693–1 and 60.693–2, except during periods of startup, shutdown, or malfunction.

(b) Compliance with §§60.692–1 to 60.692–5 and with §§60.693–1 and 60.693–2 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.696.

(c) Permission to use alternative means of emission limitation to meet the requirements of §§60.692–2 through 60.692–4 may be granted as provided in §60.694.

(d)(1) Stormwater sewer systems are not subject to the requirements of this subpart.

(2) Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily wastewater, is not subject to the requirements of this subpart.

(3) Non-contact cooling water systems are not subject to the requirements of this subpart.

(4) An owner or operator shall demonstrate compliance with the exclusions in paragraphs (d)(1), (2), and (3) of this section as provided in §60.697 (h), (i), and (j).

§60.692-2 Standards: Individual drain systems.

(a)(1) Each drain shall be equipped with water seal controls.

(2) Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.

(3) Except as provided in paragraph (a)(4) of this section, each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions.

(4) As an alternative to the requirements in paragraph (a)(3) of this section, if an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of service, inspections shall be conducted initially and semiannually to ensure caps or plugs are in place and properly installed.

(5) Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in §60.692–6.

(b)(1) Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.

(2) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.

(3) Junction boxes shall be visually inspected initially and semiannually thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(4) If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in §60.692–6.

(c)(1) Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

(2) The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions.

(3) Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in §60.692–6.

(d) Except as provided in paragraph (e) of this section, each modified or reconstructed individual drain system that has a catch basin in the existing configuration prior to May 4, 1987 shall be exempt from the provisions of this section.

(e) Refinery wastewater routed through new process drains and a new first common downstream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

§60.692-3 Standards: Oil-water separators.

(a) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart shall be equipped and operated with a fixed roof, which meets the following specifications, except as provided in paragraph (d) of this section or in §60.693–2.

(1) The fixed roof shall be installed to completely cover the separator tank, slop oil tank, storage vessel, or other auxiliary equipment with no separation between the roof and the wall.

(2) The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.

(3) If the roof has access doors or openings, such doors or openings shall be gasketed, latched, and kept closed at all times during operation of the separator system, except during inspection and maintenance.

(4) Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps occur between the roof and wall and that access doors and other openings are closed and gasketed properly.

(5) When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after it is identified, except as provided in §60.692–6.

(b) Each oil-water separator tank or auxiliary equipment with a design capacity to treat more than 16 liters per second (250 gallons per minute (gpm)) of refinery wastewater shall, in addition to the requirements in paragraph (a) of this section, be equipped and operated with a closed vent system and control device, which meet the requirements of §60.692–5, except as provided in paragraph (c) of this section or in §60.693–2.

(c)(1) Each modified or reconstructed oil-water separator tank with a maximum design capacity to treat less than 38 liters per second (600 gpm) of refinery wastewater which was equipped and operated with a fixed roof covering the entire separator tank or a portion of the separator tank prior to May 4, 1987 shall be exempt from the requirements of paragraph (b) of this section, but shall meet the requirements of paragraph (a) of this section, or may elect to comply with paragraph (c)(2) of this section.

(2) The owner or operator may elect to comply with the requirements of paragraph (a) of this section for the existing fixed roof covering a portion of the separator tank and comply with the requirements for floating roofs in §60.693–2 for the remainder of the separator tank.

(d) Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in §§60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, subparts K, Ka, or Kb are not subject to the requirements of this section.

(e) Slop oil from an oil-water separator tank and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system. Once slop oil is returned to the process unit or is disposed of, it is no longer within the scope of this subpart. Equipment used in handling slop oil shall be equipped with a fixed roof meeting the requirements of paragraph (a) of this section.

(f) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment that is required to comply with paragraph (a) of this section, and not paragraph (b) of this section, may be equipped with a pressure control valve as necessary for proper system operation. The pressure control valve shall be set at the maximum pressure necessary for proper system operation, but such that the value will not vent continuously.

§60.692-4 Standards: Aggregate facility.

A new, modified, or reconstructed aggregate facility shall comply with the requirements of §§60.692–2 and 60.692–3.

§60.692-5 Standards: Closed vent systems and control devices.

(b) Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater.

(d) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(e)(1) Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined during the initial and semiannual inspections by the methods specified in §60.696.

(2) Closed vent systems shall be purged to direct vapor to the control device.

(3) A flow indicator shall be installed on a vent stream to a control device to ensure that the vapors are being routed to the device.

(4) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(5) When emissions from a closed system are detected, first efforts at repair to eliminate the emissions shall be made as soon as practicable, but not later than 30 calendar days from the date the emissions are detected, except as provided in §60.692–6.

§60.692-6 Standards: Delay of repair.

(a) Delay of repair of facilities that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown.

(b) Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

§60.692-7 Standards: Delay of compliance.

(a) Delay of compliance of modified individual drain systems with ancillary downstream treatment components will be allowed if compliance with the provisions of this subpart cannot be achieved without a refinery or process unit shutdown.

(b) Installation of equipment necessary to comply with the provisions of this subpart shall occur no later than the next scheduled refinery or process unit shutdown.

§60.693-2 Alternative standards for oil-water separators.

(a) An owner or operator may elect to construct and operate a floating roof on an oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart which meets the following specifications.

(1) Each floating roof shall be equipped with a closure device between the wall of the separator and the roof edge. The closure device is to consist of a primary seal and a secondary seal.

(i) The primary seal shall be a liquid-mounted seal or a mechanical shoe seal.

(A) A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the separator and the floating roof. A mechanical shoe seal means a metal sheet held vertically against the wall of the separator by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(B) The gap width between the primary seal and the separator wall shall not exceed 3.8 cm (1.5 in.) at any point.

(C) The total gap area between the primary seal and the separator wall shall not exceed 67 cm^2/m (3.2 $in.^2$/ft) of separator wall perimeter.

(ii) The secondary seal shall be above the primary seal and cover the annular space between the floating roof and the wall of the separator.

(A) The gap width between the secondary seal and the separator wall shall not exceed 1.3 cm (0.5 in.) at any point.

(B) The total gap area between the secondary seal and the separator wall shall not exceed 6.7 cm^2/m (0.32 $in.^2$/ft) of separator wall perimeter.

(iii) The maximum gap width and total gap area shall be determined by the methods and procedures specified in §60.696(d).

(A) Measurement of primary seal gaps shall be performed within 60 calendar days after initial installation of the floating roof and introduction of refinery wastewater and once every 5 years thereafter.

(B) Measurement of secondary seal gaps shall be performed within 60 calendar days of initial introduction of refinery wastewater and once every year thereafter.

(iv) The owner or operator shall make necessary repairs within 30 calendar days of identification of seals not meeting the requirements listed in paragraphs (a)(1) (i) and (ii) of this section.

(2) Except as provided in paragraph (a)(4) of this section, each opening in the roof shall be equipped with a gasketed cover, seal, or lid, which shall be maintained in a closed position at all times, except during inspection and maintenance.

(3) The roof shall be floating on the liquid (i.e., off the roof supports) at all times except during abnormal conditions (i.e., low flow rate).

(4) The floating roof may be equipped with one or more emergency roof drains for removal of stormwater. Each emergency roof drain shall be fitted with a slotted membrane fabric cover that covers at least 90 percent of the drain opening area or a flexible fabric sleeve seal.

(5)(i) Access doors and other openings shall be visually inspected initially and semiannually thereafter to ensure that there is a tight fit around the edges and to identify other problems that could result in VOC emissions.

(ii) When a broken seal or gasket on an access door or other opening is identified, it shall be repaired as soon as practicable, but not later than 30 calendar days after it is identified, except as provided in §60.692–6.

(b) An owner or operator must notify the Administrator in the report required by 40 CFR 60.7 that the owner or operator has elected to construct and operate a floating roof under paragraph (a) of this section.

(c) For portions of the oil-water separator tank where it is infeasible to construct and operate a floating roof, such as the skimmer mechanism and weirs, a fixed roof meeting the requirements of §60.692–3(a) shall be installed.

(d) Except as provided in paragraph (c) of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator does not need to comply with the provisions of §§60.692–3 or 60.694 applicable to the same facilities.

§60.695 Monitoring of operations.

(a) Each owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator.

(3) Where a carbon adsorber is used for VOC emissions reduction, a monitoring device that continuously indicates and records the VOC concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device (e.g., a carbon canister), the concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and organic concentration in the gas stream vented to the carbon adsorption system.

§60.696 Performance test methods and procedures and compliance provisions.

(a) Before using any equipment installed in compliance with the requirements of §60.692–2, §60.692–3, §60.692–4, §60.692–5, or §60.693, the owner or operator shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of this subpart not to be met. Points of inspection shall include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

(b) The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.692–5 (other than a flare) is exempt from §60.8 of the General Provisions and shall use Method 21 to measure the emission concentrations, using 500 ppm as the no detectable emission limit. The instrument shall be calibrated each day before using. The calibration gases shall be:

(1) Zero air (less than 10 ppm of hydrocarbon in air), and

(2) A mixture of either methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(d) After installing the control equipment required to meet §60.693–2(a) or whenever sources that have ceased to treat refinery wastewater for a period of 1 year or more are placed back into service, the owner or operator shall determine compliance with the standards in §60.693–2(a) as follows:

(1) The maximum gap widths and maximum gap areas between the primary seal and the separator wall and between the secondary seal and the separator wall shall be determined individually within 60 calendar days of the initial installation of the floating roof and introduction of refinery wastewater or 60 calendar days after the equipment is placed back into service using the following procedure when the separator is filled to the design operating level and when the roof is floating off the roof supports.

(i) Measure seal gaps around the entire perimeter of the separator in each place where a 0.32 cm (0.125 in.) diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the separator and measure the gap width and parametrical distance of each such location.

(ii) The total surface area of each gap described in (d)(1)(i) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the wall to the seal and multiplying each such width by its respective perimetrical distance.

(iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually, divide the sum for each seal by the nominal perimeter of the separator basin and compare each to the maximum gap area as specified in §60.693–2.

(2) The gap widths and total gap area shall be determined using the procedure in paragraph (d)(1) of this section according to the following frequency:

(i) For primary seals, once every 5 years.

(ii) For secondary seals, once every year.

§60.697 Recordkeeping requirements.

(a) Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. All records shall be retained for a period of 2 years after being recorded unless otherwise noted.

(b)(1) For individual drain systems subject to §60.692–2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions, as determined during the initial and periodic visual or physical inspection.

(2) For junction boxes subject to §60.692–2, the location, date, and corrective action shall be recorded for inspections required by §60.692–2(b) when a broken seal, gap, or other problem is identified that could result in VOC emissions.

(3) For sewer lines subject to §§60.692–2 and 60.693–1(e), the location, date, and corrective action shall be recorded for inspections required by §§60.692–2(c) and 60.693–1(e) when a problem is identified that could result in VOC emissions.

(c) For oil-water separators subject to §60.692–3, the location, date, and corrective action shall be recorded for inspections required by §60.692–3(a) when a problem is identified that could result in VOC emissions.

(d) For closed vent systems subject to §60.692–5 and completely closed drain systems subject to §60.693–1, the location, date, and corrective action shall be recorded for inspections required by §60.692–5(e) during which detectable emissions are measured or a problem is identified that could result in VOC emissions.

(e)(1) If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.

(2) The reason for the delay as specified in §60.692–6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.

(3) The signature of the owner or operator (or designee) whose decision it was that repair could not be effected without refinery or process shutdown shall be recorded.

(4) The date of successful repair or corrective action shall be recorded.

(f)(1) A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location.

(2) The following information pertaining to the design specifications shall be kept.

(i) Detailed schematics, and piping and instrumentation diagrams.

(ii) The dates and descriptions of any changes in the design specifications.

(3) The following information pertaining to the operation and maintenance of closed drain systems and closed vent systems shall be kept in a readily accessible location.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions shall be kept for the life of the facility. This documentation is to include a general description of the gas streams that enter the control device, including flow and volatile organic compound content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C (1,500 °F) is used to meet the 95-percent

requirement, documentation that those conditions exist is sufficient to meet the requirements of this paragraph.

(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

(iii) Periods when the closed vent systems and control devices required in §60.692 are not operated as designed, including periods when a flare pilot does not have a flame shall be recorded and kept for 2 years after the information is recorded.

(iv) Dates of startup and shutdown of the closed vent system and control devices required in §60.692 shall be recorded and kept for 2 years after the information is recorded.

(v) The dates of each measurement of detectable emissions required in §§60.692, 60.693, or 60.692–5 shall be recorded and kept for 2 years after the information is recorded.

(vi) The background level measured during each detectable emissions measurement shall be recorded and kept for 2 years after the information is recorded.

(vii) The maximum instrument reading measured during each detectable emission measurement shall be recorded and kept for 2 years after the information is recorded.

(x) Each owner or operator of an affected facility that uses a carbon adsorber shall maintain continuous records of the VOC concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average VOC concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

(B) If a carbon adsorber that is not regenerated directly onsite in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time that the existing carbon in the control device is replaced with fresh carbon.

(g) If an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of active service, the owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which indicate the location of such drains.

(h) For stormwater sewer systems subject to the exclusion in §60.692–1(d)(1), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.

(i) For ancillary equipment subject to the exclusion in §60.692–1(d)(2), an owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which demonstrate that the ancillary equipment does not come in contact with or store oily wastewater.

(j) For non-contact cooling water systems subject to the exclusion in §60.692–1(d)(3), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the cooling water does not contact hydrocarbons or oily wastewater and is not recirculated through a cooling tower.

(k) For oil-water separators subject to §60.693–2, the location, date, and corrective action shall be recorded for inspections required by §§60.693–2(a)(1)(iii)(A) and (B), and shall be maintained for the time period specified in paragraphs (k)(1) and (2) of this section.

(1) For inspections required by §60.693-2(a)(1)(iii)(A), ten years after the information is recorded.

(2) For inspections required by §60.693–2(a)(1)(iii)(B), two years after the information is recorded.

§60.698 Reporting requirements.

(a) An owner or operator electing to comply with the provisions of §60.693 shall notify the Administrator of the alternative standard selected in the report required in §60.7.

(b)(1) Each owner or operator of a facility subject to this subpart shall submit to the Administrator within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, junction boxes, oil-water separators, and closed vent systems and control devices have been carried out in accordance with these standards. Thereafter, the owner or operator shall submit to the Administrator semiannually a certification that all of the required inspections have been carried out in accordance with these standards.

(2) Each owner or operator of an affected facility that uses a flare shall submit to the Administrator within 60 days after initial startup, as required under §60.8(a), a report of the results of the performance test required in §60.696(c).

(c) A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually thereafter to the Administrator.

(d) As applicable, a report shall be submitted semiannually to the Administrator that indicates:

(3) Each 3-hour period of operation during which the average VOC concentration level or reading of organics in the exhaust gases from a carbon adsorber is more than 20 percent greater than the design exhaust gas concentration level or reading.

(ii) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly onsite in the control device is not replaced at the predetermined interval specified in §60.695(a)(3)(ii).

(e) If compliance with the provisions of this subpart is delayed pursuant to §60.692–7, the notification required under 40 CFR 60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or process unit shutdown.

SECTION E.7 40 CFR Part 60, Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquid for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973 and Prior to May 19, 1978

E.7.1 General Provisions Relating to NSPS Subpart K [326 IAC 12-1] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR Part 60.1(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for storage tanks 3534, 3537, 3601, and 3605, except when otherwise specified in 40 CFR Part 60, Subpart K.

E.7.2 NSPS Requirements [40 CFR Part 60, Subpart K] [326 IAC 12]

Pursuant to 40 CFR 60.110(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart K, which are incorporated by reference as 326 IAC 12, for the storage tanks listed in Condition E.7.1, as specified below:

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978

§60.110 Applicability and designation of affected facility.

(a) Except as provided in §60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,412 liters (40,000 gallons).

(c) Subject to the requirements of this subpart is any facility under paragraph (a) of this section which:

(1) Has a capacity greater than 151, 416 liters (40,000 gallons), but not exceeding 246,052 liters (65,000 gallons), and commences construction or modification after March 8, 1974, and prior to May 19, 1978.

(2) Has a capacity greater than 246,052 liters (65,000 gallons) and commences construction or modification after June 11, 1973, and prior to May 19, 1978.

§60.112 Standard for volatile organic compounds (VOC).

(a) The owner or operator of any storage vessel to which this subpart applies shall store petroleum liquids as follows:

(1) If the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

(2) If the true vapor pressure of the petroleum liquid as stored is greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a vapor recovery system or its equivalent.

§60.113 Monitoring of operations.

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be

determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each affected facility which stores petroleum liquids with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

(2) Each owner or operator of each affected facility equipped with a vapor recovery and return or disposal system in accordance with the requirements of §60.112.

SECTION E.8 40 CFR Part 60, Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquid for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984

E.8.1 General Provisions Relating to NSPS Subpart Ka [326 IAC 12-1] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR Part 60.1(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for storage tanks 3480, 3487, 3525, 3526, 3553, 3554, 3602, 3604, 3704, 3915, 3916, 3917, 3918, 3919, and 3920, except when otherwise specified in 40 CFR Part 60, Subpart Ka.

E.8.2 NSPS Requirements [40 CFR Part 60, Subpart Ka] [326 IAC 12]

Pursuant to 40 CFR 60.110(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart Ka, which are incorporated by reference as 326 IAC 12, for the storage tanks listed in Condition E.8.1, as specified in this condition. Storage tanks 3602 and 3604 shall comply only with the record keeping requirements in 40 CFR 60.115a(a).

Subpart Ka—Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984

§60.110a Applicability and designation of affected facility.

(a) Affected facility. Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a storage capacity greater than 151,416 liters (40,000 gallons) that is used to store petroleum liquids for which construction is commenced after May 18, 1978.

(b) Each petroleum liquid storage vessel with a capacity of less than 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer is not an affected facility and, therefore, is exempt from the requirements of this subpart.

§60.112a Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure equal to or greater than 10.3 kPa (1.5 psia) but not greater than 76.6 kPa (11.1 psia) shall equip the storage vessel with one of the following:

(1) An external floating roof, consisting of a pontoon-type or double-deck-type cover that rests on the surface of the liquid contents and is equipped with a closure device between the tank wall and the roof edge. Except as provided in paragraph (a)(1)(ii)(D) of this section, the closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal. The roof is to be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(i) The primary seal is to be either a metallic shoe seal, a liquid-mounted seal, or a vapor-mounted seal. Each seal is to meet the following requirements:

(A) The accumulated area of gaps between the tank wall and the metallic shoe seal or the liquid-mounted seal shall not exceed 212 cm^2 per meter of tank diameter (10.0 in^2 per ft of tank diameter) and the width of any portion of any gap shall not exceed 3.81 cm (1 1/2 in).

(B) The accumulated area of gaps between the tank wall and the vapor-mounted seal shall not exceed 21.2 cm^2 per meter of tank diameter (1.0 in^2 per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (1/2 in).

(C) One end of the metallic shoe is to extend into the stored liquid and the other end is to extend a minimum vertical distance of 61 cm (24 in) above the stored liquid surface.

(D) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (a)(1)(ii)(B) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal used in combination with a metallic shoe or liquid-mounted primary seal shall not exceed 21.2 cm^2 per meter of tank diameter (1.0 in^2 per ft. of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (1/2 in.). There shall be no gaps between the tank wall and the secondary seal used in combination with a vapor-mounted primary seal.

(C) There are to be no holes, tears or other openings in the seal or seal fabric.

(D) The owner or operator is exempted from the requirements for secondary seals and the secondary seal gap criteria when performing gap measurements or inspections of the primary seal.

(iii) Each opening in the roof except for automatic bleeder vents and rim space vents is to provide a projection below the liquid surface. Each opening in the roof except for automatic bleeder vents, rim space vents and leg sleeves is to be equipped with a cover, seal or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use or as described in paragraph (a)(1)(iv) of this section. Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting.

(iv) Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(2) A fixed roof with an internal floating type cover equipped with a continuous closure device between the tank wall and the cover edge. The cover is to be floating at all times, (i.e., off the leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the cover is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. Each opening in the cover except for automatic bleeder vents and the rim space vents is to provide a projection below the liquid surface. Each opening in the cover except for automatic bleeder vents, rim space vents, stub drains and leg sleeves is to be equipped with a cover, seal, or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the cover is floating except when the cover is being floated off or is being landed on the leg supports. Rim vents are to be set to open only when the cover is being floated off the leg supports or at the manufacturer's recommended setting.

§60.113a Testing and procedures.

(a) Except as provided in §60.8(b) compliance with the standard prescribed in §60.112a shall be determined as follows or in accordance with an equivalent procedure as provided in §60.114a.

(1) The owner or operator of each storage vessel to which this subpart applies which has an external floating roof shall meet the following requirements:

(i) Determine the gap areas and maximum gap widths between the primary seal and the tank wall and between the secondary seal and the tank wall according to the following frequency:

(A) For primary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every five years thereafter. All primary seal inspections or gap measurements which require the removal or dislodging of the secondary seal shall be accomplished as rapidly as possible and the secondary seal shall be replaced as soon as possible.

(B) For secondary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every year thereafter.

(C) If any storage vessel is out of service for a period of one year or more, subsequent refilling with petroleum liquid shall be considered initial fill for the purposes of paragraphs (a)(1)(i)(A) and (a)(1)(i)(B) of this section.

(D) Keep records of each gap measurement at the plant for a period of at least 2 years following the date of measurement. Each record shall identify the vessel on which the measurement was performed and shall contain the date of the seal gap measurement, the raw data obtained in the measurement process required by paragraph (a)(1)(ii) of this section and the calculation required by paragraph (a)(1)(iii) of this section.

(E) If either the seal gap calculated in accord with paragraph (a)(1)(iii) of this section or the measured maximum seal gap exceeds the limitations specified by §60.112a of this subpart, a report shall be furnished to the Administrator within 60 days of the date of measurements. The report shall identify the vessel and list each reason why the vessel did not meet the specifications of §60.112a. The report shall also describe the actions necessary to bring the storage vessel into compliance with the specifications of §60.112a.

(ii) Determine gap widths in the primary and secondary seals individually by the following procedures:

(A) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(B) Measure seal gaps around the entire circumference of the tank in each place where a 1/8&inch; diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the tank wall and measure the circumferential distance of each such location.

(C) The total surface area of each gap described in paragraph (a)(1)(ii)(B) of this section shall be determined by using probes of various widths to accurately measure the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually. Divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the appropriate ratio in the standard in §60.112a(a)(1)(i) and §60.112a(a)(1)(ii).

(iv) Provide the Administrator 30 days prior notice of the gap measurement to afford the Administrator the opportunity to have an observer present.

§60.115a Monitoring of operations.

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be

determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each storage vessel storing a petroleum liquid with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

SECTION E.9 40 CFR Part 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

E.9.1 General Provisions Relating to NSPS Subpart Kb [326 IAC 12-1] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR Part 60.1(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for storage tanks 3474, 3475, 3476, 3484, 3488, 3489, 3493, 3514, 3527, 3528, 3531, 3549, 3558, 3600, 3622, 3629, 3701, 3702, 3715, 3716, 3860, 3900, 3904, 3907, and 3911, except when otherwise specified in 40 CFR Part 60, Subpart Kb.

E.9.2 NSPS Requirements [40 CFR Part 60, Subpart Kb] [326 IAC 12]

Pursuant to 40 CFR 60.110(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart Kb, which are incorporated by reference as 326 IAC 12, for the storage tanks listed in Condition E.9.1, as specified below:

Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

§60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

(d) This subpart does not apply to the following:

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.

§60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the

process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in §60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in §60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

§60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in §60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of §60.112b.

(a) After installing the control equipment required to meet §60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in §60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and

(a)(3)(ii) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet §60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4) (i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 Cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of §60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

§60.115b Reporting and recordkeeping requirements.

The owner or operator of each storage vessel as specified in §60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of §60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with §60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(1) and §60.113b(a)(1). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Keep a record of each inspection performed as required by §60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the

date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in §60.113b(a)(2) are detected during the annual visual inspection required by §60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by §60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in §60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of §61.112b(a)(1) or §60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with §61.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(2) and §60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by §60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by §60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by §60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

§60.116b Monitoring of operations.

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in §60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 15.0

kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or

(ii) Determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

SECTION E.10 40 CFR Part 63, Subpart UUU – National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

E.10.1 General Provisions Relating to NESHAP Subpart UUU [40 CFR Part 63, Subpart Y] [326 IAC 20-1]

Pursuant to 40 CFR Part 63.1577, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, as specified in Table 44 of 40 CFR Part 63, Subpart UUU in accordance with the schedule in 40 CFR Part 63, Subpart UUU.

E.10.2 NESHAP Subpart UUU Requirements [40 CFR Part 63, Subpart UUU] [326 IAC 20-50-1]

Pursuant to 40 CFR 63.1561, the Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart UUU, which are incorporated by reference as 326 IAC 20-50-1 for the Sodium Bisulfite and Beavon – Stretford Tail Gas Units (Section D.4), 3UF Catalyst regenerator (Section D.15), 4UF catalyst regenerator and bypass line (Section D.16), FCU 500 catalyst regenerator (Section D.21), and FCU 600 catalyst regenerator (Section D.22).

Subpart UUU—National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

§63.1562 What parts of my plant are covered by this subpart?

(a) This subpart applies to each new, reconstructed, or existing affected source at a petroleum refinery.

(b) The affected sources are:

(1) The process vent or group of process vents on fluidized catalytic cracking units that are associated with regeneration of the catalyst used in the unit (i.e., the catalyst regeneration flue gas vent).

(2) The process vent or group of process vents on catalytic reforming units (including but not limited to semi-regenerative, cyclic, or continuous processes) that are associated with regeneration of the catalyst used in the unit. This affected source includes vents that are used during the unit depressurization, purging, coke burn, and catalyst rejuvenation.

(3) The process vent or group of process vents on Claus or other types of sulfur recovery plant units or the tail gas treatment units serving sulfur recovery plants, that are associated with sulfur recovery.

(4) Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit. This means each vent system that contains a bypass line (e.g., ductwork) that could divert an affected vent stream away from a control device used to comply with the requirements of this subpart.

(d) Any affected source is reconstructed if you meet the criteria in §63.2.

(e) An affected source is existing if it is not new or reconstructed.

(f) This subpart does not apply to:

(1) A thermal catalytic cracking unit.

(2) A sulfur recovery unit that does not recover elemental sulfur or where the modified reaction is carried out in a water solution which contains a metal ion capable of oxidizing the sulfide ion to sulfur (e.g., the LO-CAT II process).

(3) A redundant sulfur recovery unit not located at a petroleum refinery and used by the refinery only for emergency or maintenance backup.

(4) Equipment associated with bypass lines such as low leg drains, high point bleed, analyzer vents, open-ended valves or lines, or pressure relief valves needed for safety reasons.

(5) Gaseous streams routed to a fuel gas system.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005]

§63.1563 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to the requirements in paragraphs (a)(1) and (2) of this section.

(1) If you startup your affected source before April 11, 2002, then you must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart no later than April 11, 2002.

(2) If you startup your affected source after April 11, 2002, you must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart upon startup of your affected source.

(b) If you have an existing affected source, you must comply with the emission limitations and work practice standards for existing affected sources in this subpart by no later than April 11, 2005 except as specified in paragraph (c) of this section.

(e) You must meet the notification requirements in §63.1574 according to the schedule in §63.1574 and in 40 CFR part 63, subpart A. Some of the notifications must be submitted before the date you are required to comply with the emission limitations and work practice standards in this subpart.

Catalytic Cracking Units, Catalytic Reforming Units, Sulfur Recovery Units, and Bypass Lines

§63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?

(a) What emission limitations and work practice standards must I meet? You must:

(1) Meet each emission limitation in Table 1 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for PM in §60.102 of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit isn't subject to the NSPS for PM, you can choose from the four options in paragraphs (a)(1)(i) through (iv) of this section:

(i) You can elect to comply with the NSPS requirements (Option 1);

(2) Comply with each operating limit in Table 2 of this subpart that applies to you.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(4) The emission limitations and operating limits for metal HAP emissions from catalytic cracking units required in paragraphs (a)(1) and (2) of this section do not apply during periods of planned maintenance preapproved by the applicable permitting authority according to the requirements in §63.1575(j).

(b) How do I demonstrate initial compliance with the emission limitations and work practice standard? You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in §63.1572 and Table 3 of this subpart.

(2) Conduct a performance test for each catalytic cracking unit not subject to the NSPS for PM according to the requirements in §63.1571 and under the conditions specified in Table 4 of this subpart.

(4) Use the procedures in paragraphs (b)(4)(i) through (iv) of this section to determine initial compliance with the emission limitations.

(i) If you elect Option 1 in paragraph (a)(1)(i) of this section, the NSPS requirements, compute the PM emission rate (lb/1,000 lbs of coke burn-off) for each run using Equations 1, 2, and 3 (if applicable) of this section as follows:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r [(\%CO/2) + \%CO_2 + \%O_2] + K_3 Q_{oxy} (\%O_{xy}) \qquad \text{(Eq. 1)}$$

Where:

R_c = Coke burn-off rate, kg/hr (lb/hr);

Q_r = Volumetric flow rate of exhaust gas from catalyst regenerator before adding air or gas streams. Example: You may measure upstream or downstream of an electrostatic precipitator, but you must measure upstream of a carbon monoxide boiler, dscm/min (dscf/min). You may use the alternative in either §63.1573(a)(1) or (a)(2), as applicable, to calculate Q_r;

Q_a = Volumetric flow rate of air to catalytic cracking unit catalyst regenerator, as determined from instruments in the catalytic cracking unit control room, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in regenerator exhaust, percent by volume (dry basis);

%CO = Carbon monoxide concentration in regenerator exhaust, percent by volume (dry basis);

$\%O_2$ = Oxygen concentration in regenerator exhaust, percent by volume (dry basis);

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) (0.0186 (lb-min)/(hr-dscf-%));

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) (0.1303 (lb-min)/(hr-dscf));

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) (0.0062 (lb-min)/(hr-dscf-%));

Q_{oxy} = Volumetric flow rate of oxygen-enriched air stream to regenerator, as determined from instruments in the catalytic cracking unit control room, dscm/min (dscf/min); and

$\%O_{xy}$ = Oxygen concentration in oxygen-enriched air stream, percent by volume (dry basis).

$$E = \frac{K \times C_s \times Q_{sd}}{R_c} \qquad \text{(Eq. 2)}$$

Where:

E = Emission rate of PM, kg/1,000 kg (lb/1,000 lb) of coke burn-off;

C_s = Concentration of PM, g/dscm (lb/dscf);

Q_{sd} = Volumetric flow rate of the catalytic cracking unit catalyst regenerator flue gas as measured by Method 2 in appendix A to part 60 of this chapter, dscm/hr (dscf/hr);

R_c = Coke burn-off rate, kg coke/hr (1,000 lb coke/hr); and

K = Conversion factor, 1.0 (kg^2/g)/(1,000 kg) (1,000 lb/(1,000 lb)).

$$E_s = 1.0 + A(H/R_c)K' \qquad \text{(Eq. 3)}$$

Where:

E_s = Emission rate of PM allowed, kg/1,000 kg (1b/1,000 lb) of coke burn-off in catalyst regenerator;

1.0 = Emission limitation, kg coke/1,000 kg (lb coke/1,000 lb);

A = Allowable incremental rate of PM emissions, 0.18 g/million cal (0.10 lb/million Btu); and

H = Heat input rate from solid or liquid fossil fuel, million cal/hr (million Btu/hr). Make sure your permitting authority approves procedures for determining the heat input rate.

R_c = Coke burn-off rate, kg coke/hr (1,000 lb coke/hr) determined using Equation 1 of this section; and

K′ = Conversion factor to units to standard, 1.0 (kg^2 /g)/(1,000 kg) (10^3 lb/(1,000 lb)).

(5) Demonstrate initial compliance with each emission limitation that applies to you according to Table 5 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting your operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(7) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 1 and 2 of this subpart that applies to you according to the methods specified in Tables 6 and 7 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by maintaining records to document conformance with the procedures in your operation, maintenance, and monitoring plan.

§63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?

(a) What emission limitations and work practice standards must I meet? You must:

(1) Meet each emission limitation in Table 8 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for carbon monoxide (CO) in §60.103 of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit isn't subject to the NSPS for CO, you can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(ii) You can elect to comply with the CO emission limit (Option 2).

(2) Comply with each site-specific operating limit in Table 9 of this subpart that applies to you.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(4) The emission limitations and operating limits for organic HAP emissions from catalytic cracking units required in paragraphs (a)(1) and (2) of this section do not apply during periods of planned maintenance preapproved by the applicable permitting authority according to the requirements in §63.1575(j).

(b) How do I demonstrate initial compliance with the emission limitations and work practice standards? You must:

(1) Install, operate, and maintain a continuous monitoring system according to the requirements in §63.1572 and Table 10 of this subpart. Except:

(2) Conduct each performance test for a catalytic cracking unit not subject to the NSPS for CO according to the requirements in §63.1571 and under the conditions specified in Table 11 of this subpart.

(4) Demonstrate initial compliance with each emission limitation that applies to you according to Table 12 of this subpart.

(5) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status according to §63.1574.

(6) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 8 and 9 of this subpart that applies to you according to the methods specified in Tables 13 and 14 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

§63.1566 What are my requirements for organic HAP emissions from catalytic reforming units?

(a) What emission limitations and work practice standards must I meet? You must:

(1) Meet each emission limitation in Table 15 of this subpart that applies to you. You can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to vent emissions of total organic compounds (TOC) to a flare that meets the control device requirements in §63.11(b) (Option 1); or

(2) Comply with each site-specific operating limit in Table 16 of this subpart that applies to you.

(3) Except as provided in paragraph (a)(4) of this section, the emission limitations in Tables 15 and 16 of this subpart apply to emissions from catalytic reforming unit process vents associated with initial catalyst depressuring and catalyst purging operations that occur prior to the coke burn-off cycle. The emission limitations in Tables 15 and 16 of this subpart do not apply to the coke burn-off, catalyst rejuvenation, reduction or activation vents, or to the control systems used for these vents.

(4) The emission limitations in Tables 15 and 16 of this subpart do not apply to emissions from process vents during depressuring and purging operations when the reactor vent pressure is 5 pounds per square inch gauge (psig) or less.

(5) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(b) How do I demonstrate initial compliance with the emission limitations and work practice standard? You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in §63.1572 and Table 17 of this subpart.

(2) Conduct each performance test for a catalytic reforming unit according to the requirements in §63.1571 and under the conditions specified in Table 18 of this subpart.

(3) Establish each site-specific operating limit in Table 16 of this subpart that applies to you according to the procedures in Table 18 of this subpart.

(5) You are not required to do a TOC performance test if:

(i) You elect to vent emissions to a flare as provided in paragraph (a)(1)(i) of this section (Option 1); or

(6) Demonstrate initial compliance with each emission limitation that applies to you according to Table 19 of this subpart.

(7) Demonstrate initial compliance with the work practice standard in paragraph (a)(5) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(8) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 15 and 16 of this subpart that applies to you according to the methods specified in Tables 20 and 21 of this subpart.

(2) Demonstrate continuous compliance with the work practice standards in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

§63.1567 What are my requirements for inorganic HAP emissions from catalytic reforming units?

(a) What emission limitations and work practice standards must I meet? You must:

(1) Meet each emission limitation in Table 22 to this subpart that applies to you. If you operate a catalytic reforming unit in which different reactors in the catalytic reforming unit are regenerated in separate regeneration systems, then these emission limitations apply to each separate regeneration system. These emission limitations apply to emissions from catalytic reforming unit process vents associated with the coke burn-off and catalyst rejuvenation operations during coke burn-off and catalyst regeneration. You can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to meet a percent reduction standard for hydrogen chloride (HCl) emissions (Option 1); or

(ii) You can elect to meet an HCl concentration limit (Option 2).

(2) Meet each site-specific operating limit in Table 23 of this subpart that applies to you. These operating limits apply during coke burn-off and catalyst rejuvenation.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(b) How do I demonstrate initial compliance with the emission limitations and work practice standard? You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in §63.1572 and Table 24 of this subpart.

(2) Conduct each performance test for a catalytic reforming unit according to the requirements in §63.1571 and the conditions specified in Table 25 of this subpart.

(3) Establish each site-specific operating limit in Table 23 of this subpart that applies to you according to the procedures in Table 25 of this subpart.

(4) Use the equations in paragraphs (b)(4)(i) through (iv) of this section to determine initial compliance with the emission limitations.

(i) Correct the measured HCl concentration for oxygen (O_2) content in the gas stream using Equation 1 of this section as follows:

$$C_{HCl,3\%O_2} = \left(\frac{17.9\%}{20.9\% - \%O_2}\right) C_{HCl} \qquad \text{(Eq. 1)}$$

Where:

$C_{HCl,3\%O2}$ = Concentration of HCl on a dry basis in ppmv corrected to 3 percent oxygen or 1 ppmv, whichever is greater;

C_{HCl} = Concentration of HCl on a dry basis in ppmv, as measured by Method 26A in 40 CFR part 60, appendix A; and

$\%O_2$ = Oxygen concentration in percent by volume (dry basis).

(ii) If you elect the percent reduction standard, calculate the emission rate of HCl using Equation 2 of this section; then calculate the mass emission reduction from the mass emission rates using Equation 3 of this section as follows:

$$E_{HCl} = K_6 C_{HCl} Q_s \qquad \text{(Eq. 2)}$$

Where:

$E_{HCl,}$ = Emission rate of HCl in the vent stream, grams per hour;

K_6 = Constant, 0.091 (parts per million)$^{-1}$ (grams HCl per standard cubic meter) (minutes per hour), where the standard temperature (standard cubic meter) is at 20 degrees Celsius (C); and

Q_s = Vent stream flow rate, dscm/min, at a temperature of 20 degrees C.

$$HCl\%reduction = \frac{E_{HCl,i} - E_{HCl,o}}{E_{HCl,i}} \times 100\% \qquad \text{(Eq. 3)}$$

Where:

$E_{HCl,i}$ = Mass emission rate of HCl at control device inlet, g/hr; and

$E_{HCl,o}$ = Mass emission rate of HCl at control device outlet, g/hr.

(iii) If you are required to use a colormetric tube sampling system to demonstrate continuous compliance with the HCl concentration operating limit, calculate the HCl operating limit using Equation 4 of this section as follows:

$$C_{CHl,ppmvLimit} = 0.9 C_{HCl,AveTube} \left(\frac{C_{HCl,RegLimit}}{C_{HCl,3\%O_2}}\right) \qquad \text{(Eq. 4)}$$

Where:

$C_{HCl,ppmvLimit}$ = Maximum permissible HCl concentration for the HCl concentration operating limit, ppmv;

$C_{HCl,AveTube}$ = Average HCl concentration from the colormetric tube sampling system, calculated as the arithmetic average of the average HCl concentration measured for each performance test run, ppmv or 1 ppmv, whichever is greater; and

$C_{HCl,RegLimit}$ = Maximum permissible outlet HCl concentration for the applicable catalytic reforming unit as listed in Table 22 of this subpart, either 10 or 30 ppmv.

(iv) If you are required to use a colormetric tube sampling system to demonstrate continuous compliance with the percent reduction operating limit, calculate the HCl operating limit using Equation 5 of this section as follows:

$$C_{HCl,\%Limit} = 0.9C_{HCl,AveTube}\left(\frac{100 - \%HClReduction_{Limit}}{100 - \%HClReduction_{Test}}\right) \quad \text{(Eq. 5)}$$

Where:

$C_{HCl,}\%_{Limit}$ = Maximum permissible HCl concentration for the percent reduction operating limit, ppmv;

%HCl $Reduction_{Limit}$ = Minimum permissible HCl reduction for the applicable catalytic reforming unit as listed in Table 22 of this subpart, either 97 or 92 percent; and

%HCl $Reduction_{Test}$ = Average percent HCl reduction calculated as the arithmetic average HCl reduction calculated using Equation 3 of this section for each performance source test, percent.

(5) Demonstrate initial compliance with each emission limitation that applies to you according to Table 26 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(7) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) *How do I demonstrate continuous compliance with the emission limitations and work practice standard?* You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 22 and 23 of this subpart that applies to you according to the methods specified in Tables 27 and 28 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by maintaining records to document conformance with the procedures in your operation, maintenance and monitoring plan.

§63.1568 What are my requirements for HAP emissions from sulfur recovery units?

(a) What emission limitations and work practice standard must I meet? You must:

(1) Meet each emission limitation in Table 29 of this subpart that applies to you. If your sulfur recovery unit is subject to the NSPS for sulfur oxides in §60.104 of this chapter, you must meet the emission limitations for NSPS units. If your sulfur recovery unit isn't subject to the NSPS for sulfur oxides, you can choose from the options in paragraphs (a)(1)(i) through (ii) of this section:

(2) Meet each operating limit in Table 30 of this subpart that applies to you.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(b) How do I demonstrate initial compliance with the emission limitations and work practice standards? You must:

(1) Install, operate, and maintain a continuous monitoring system according to the requirements in §63.1572 and Table 31 of this subpart.

(4) Correct the reduced sulfur samples to zero percent excess air using Equation 1 of this section as follows:

$$C_{adj} = C_{meas}\left[20.9_c / (20.9 - \%O_2)\right] \qquad \text{(Eq. 1)}$$

Where:

C_{adj} = pollutant concentration adjusted to zero percent oxygen, ppm or g/dscm;

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm;

20.9_c = 20.9 percent oxygen—0.0 percent oxygen (defined oxygen correction basis), percent;

20.9 = oxygen concentration in air, percent;

$\%O_2$ = oxygen concentration measured on a dry basis, percent.

(5) Demonstrate initial compliance with each emission limitation that applies to you according to Table 33 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your notification of compliance status.

(7) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 29 and 30 of this subpart that applies to you according to the methods specified in Tables 34 and 35 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

§63.1569 What are my requirements for HAP emissions from bypass lines?

(a) *What work practice standards must I meet?* (1) You must meet each work practice standard in Table 36 of this subpart that applies to you. You can choose from the four options in paragraphs (a)(1)(i) through (iv) of this section:

(i) You can elect to install an automated system (Option 1);

(3) You must prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(b) *How do I demonstrate initial compliance with the work practice standards?* You must:

(1) If you elect the option in paragraph (a)(1)(i) of this section, conduct each performance test for a bypass line according to the requirements in §63.1571 and under the conditions specified in Table 37 of this subpart.

(2) Demonstrate initial compliance with each work practice standard in Table 36 of this subpart that applies to you according to Table 38 of this subpart.

(3) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your notification of compliance status.

(4) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) *How do I demonstrate continuous compliance with the work practice standards?* You must:

(1) Demonstrate continuous compliance with each work practice standard in Table 36 of this subpart that applies to you according to the requirements in Table 39 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(2) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

General Compliance Requirements

§63.1570 What are my general requirements for complying with this subpart?

(a) You must be in compliance with all of the non-opacity standards in this subpart during the times specified in §63.6(f)(1).

(b) You must be in compliance with the opacity and visible emission limits in this subpart during the times specified in §63.6(h)(1).

(d) You must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).

(e) During periods of startup, shutdown, and malfunction, you must operate in accordance with your SSMP.

(f) You must report each instance in which you did not meet each emission limitation and each operating limit in this subpart that applies to you. This includes periods of startup, shutdown, and malfunction. You also must report each instance in which you did not meet the work practice standards in this subpart that apply to you. These instances are deviations from the emission limitations and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.1575.

(g) Consistent with §§63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with the SSMP. The SSMP must require that good air pollution control practices are used during those periods. The plan must also include elements designed to minimize the frequency of such periods (i.e., root cause analysis). The Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e) and the contents of the SSMP.

§63.1571 How and when do I conduct a performance test or other initial compliance demonstration?

(a) *When must I conduct a performance test?* You must conduct performance tests and report the results by no later than 150 days after the compliance date specified for your source in §63.1563 and according to the provisions in §63.7(a)(2). If you are required to do a performance evaluation or test for a semi-regenerative catalytic reforming unit catalyst regenerator vent, you may do them at the first regeneration cycle after your compliance date and report the results in a followup Notification of Compliance Status report due no later than 150 days after the test.

(1) For each emission limitation or work practice standard where initial compliance is not demonstrated using a performance test, opacity observation, or visible emission observation, you must conduct the initial

compliance demonstration within 30 calendar days after the compliance date that is specified for your source in §63.1563.

(3) If you commenced construction or reconstruction between September 11, 1998 and April 11, 2002, you must demonstrate initial compliance with either the proposed emission limitation or the promulgated emission limitation no later than October 8, 2002 or within 180 calendar days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(b) *What are the general requirements for performance test and performance evaluations?* You must:

(1) Conduct each performance test according to the requirements in §63.7(e)(1).

(2) Except for opacity and visible emission observations, conduct three separate test runs for each performance test as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(3) Conduct each performance evaluation according to the requirements in §63.8(e).

(4) Not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).

(5) Calculate the average emission rate for the performance test by calculating the emission rate for each individual test run in the units of the applicable emission limitation using Equation 2, 5, or 8 of §63.1564, and determining the arithmetic average of the calculated emission rates.

(c) *What procedures must I use for an engineering assessment?* You may choose to use an engineering assessment to calculate the process vent flow rate, net heating value, TOC emission rate, and total organic HAP emission rate expected to yield the highest daily emission rate when determining the emission reduction or outlet concentration for the organic HAP standard for catalytic reforming units. If you use an engineering assessment, you must document all data, assumptions, and procedures to the satisfaction of the applicable permitting authority. An engineering assessment may include the approaches listed in paragraphs (c)(1) through (c)(4) of this section. Other engineering assessments may be used but are subject to review and approval by the applicable permitting authority.

(1) You may use previous test results provided the tests are representative of current operating practices at the process unit, and provided EPA methods or approved alternatives were used;

(2) You may use bench-scale or pilot-scale test data representative of the process under representative operating conditions;

(3) You may use maximum flow rate, TOC emission rate, organic HAP emission rate, or organic HAP or TOC concentration specified or implied within a permit limit applicable to the process vent; or

(4) You may use design analysis based on engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

(i) Use of material balances based on process stoichiometry to estimate maximum TOC concentrations;

(ii) Calculation of hourly average maximum flow rate based on physical equipment design such as pump or blower capacities; and

(iii) Calculation of TOC concentrations based on saturation conditions.

(d) *Can I adjust the process or control device measured values when establishing an operating limit?* If you do a performance test to demonstrate compliance, you must base the process or control device operating limits for continuous parameter monitoring systems on the results measured during the performance test. You may adjust the values measured during the performance test according to the criteria in paragraphs (d)(1) through (3) of this section.

(1) If you must meet the HAP metal emission limitations in §63.1564, you elect the option in paragraph (a)(1)(iii) in §63.1564 (Ni lb/hr), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration from the initial performance test. Section 63.1564(b)(2) allows you to adjust the laboratory measurements of the equilibrium catalyst Ni concentration to the maximum level. You must make this adjustment using Equation 1 of this section as follows:

$$\text{Ecat} - \text{Limit} = \frac{13\,\text{g Ni/hr}}{\text{NiEmR1}_{st}} \times \text{Ecat}_{st} \qquad \text{(Eq. 1)}$$

Where:

Ecat-Limit = Operating limit for equilibrium catalyst Ni concentration, mg/kg;

NiEmR1_{st} = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 5 of this section for each performance test run, g Ni/hr; and

Ecat_{st} = Average equilibrium Ni concentration from laboratory test results, mg/kg.

(2) If you must meet the HAP metal emission limitations in §63.1564, you elect the option in paragraph (a)(1)(iv) in §63.1564 (Ni lb/1,000 lb of coke burn-off), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration from the initial performance test. Section 63.1564(b)(2) allows you to adjust the laboratory measurements of the equilibrium catalyst Ni concentration to the maximum level. You must make this adjustment using Equation 2 of this section as follows:

$$\text{Ecat} - \text{Limit} = \frac{1.0\,\text{mg/kg coke burn-off}}{\text{NiEmR2}_{st}} \times \text{Ecat}_{st} \qquad \text{(Eq. 2)}$$

Where:

NiEmR2_{st} = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 8 of §63.1564 for each performance test run, mg/kg coke burn-off.

(3) If you choose to adjust the equilibrium catalyst Ni concentration to the maximum level, you can't adjust any other monitored operating parameter (i.e., gas flow rate, voltage, pressure drop, liquid-to-gas ratio).

(4) Except as specified in paragraph (d)(3) of this section, if you use continuous parameter monitoring systems, you may adjust one of your monitored operating parameters (flow rate, voltage and secondary current, pressure drop, liquid-to-gas ratio) from the average of measured values during the performance test to the maximum value (or minimum value, if applicable) representative of worst-case operating conditions, if necessary. This adjustment of measured values may be done using control device design specifications, manufacturer recommendations, or other applicable information. You must provide supporting documentation and rationale in your Notification of Compliance Status, demonstrating to the satisfaction of your permitting authority, that your affected source complies with the applicable emission limit at the operating limit based on adjusted values.

(e) Can I change my operating limit? You may change the established operating limit by meeting the requirements in paragraphs (e)(1) through (3) of this section.

(1) You may change your established operating limit for a continuous parameter monitoring system by doing an additional performance test, a performance test in conjunction with an engineering assessment, or an additional performance test, a performance test in conjunction with an engineering assessment, or an engineering assessment to verify that, at the new operating limit, you are in compliance with the applicable emission limitation.

(2) You must establish a revised operating limit for your continuous parameter monitoring system if you make any change in process or operating conditions that could affect control system performance or you change designated conditions after the last performance or compliance tests were done. You can establish the revised operating limit as described in paragraph (e)(1) of this section.

§63.1572 What are my monitoring installation, operation, and maintenance requirements?

(a) You must install, operate, and maintain each continuous emission monitoring system according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) You must install, operate, and maintain each continuous emission monitoring system according to the requirements in Table 40 of this subpart.

(2) If you use a continuous emission monitoring system to meet the NSPS CO or SO_2 limit, you must conduct a performance evaluation of each continuous emission monitoring system according to the requirements in §63.8 and Table 40 of this subpart. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.

(3) As specified in §63.8(c)(4)(ii), each continuous emission monitoring system must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Data must be reduced as specified in §63.8(g)(2).

(b) You must install, operate, and maintain each continuous opacity monitoring system according to the requirements in paragraphs (b)(1) through (3) of this section.

(1) Each continuous opacity monitoring system must be installed, operated, and maintained according to the requirements in Table 40 of this subpart.

(2) If you use a continuous opacity monitoring system to meet the NSPS opacity limit, you must conduct a performance evaluation of each continuous opacity monitoring system according to the requirements in §63.8 and Table 40 of this subpart. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.

(3) As specified in §63.8(c)(4)(i), each continuous opacity monitoring system must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(c) Your must install, operate, and maintain each continuous parameter monitoring system according to the requirements in paragraphs (c)(1) through (5) of this section.

(1) The owner or operator shall install, operate, and maintain each continuous parameter monitoring system in a manner consistent with the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately. The owner or operator shall also meet the equipment specifications in Table 41 of this subpart if pH strips or colorimetric tube sampling systems are used.

(2) The continuous parameter monitoring system must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data (or at least two if a calibration check is performed during that hour or if the continuous parameter monitoring system is out-of-control).

(3) Each continuous parameter monitoring system must have valid hourly average data from at least 75 percent of the hours during which the process operated.

(4) Each continuous parameter monitoring system must determine and record the hourly average of all recorded readings and if applicable, the daily average of all recorded readings for each operating day.

The daily average must cover a 24-hour period if operation is continuous or the number of hours of operation per day if operation is not continuous.

(5) Each continuous parameter monitoring system must record the results of each inspection, calibration, and validation check.

(d) You must monitor and collect data according to the requirements in paragraphs (d)(1) and (2) of this section.

(1) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation (or collect data at all required intervals) at all times the affected source is operating.

(2) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities for purposes of this regulation, including data averages and calculations, for fulfilling a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

§63.1573 What are my monitoring alternatives?

(a) *What are the approved alternatives for measuring gas flow rate?* (1) You may use this alternative to a continuous parameter monitoring system for the catalytic regenerator exhaust gas flow rate for your catalytic cracking unit if the unit does not introduce any other gas streams into the catalyst regeneration vent (i.e., complete combustion units with no additional combustion devices). You may also use this alternative to a continuous parameter monitoring system for the catalytic regenerator atmospheric exhaust gas flow rate for your catalytic reforming unit during the coke burn and rejuvenation cycles if the unit operates as a constant pressure system during these cycles. If you use this alternative, you shall use the same procedure for the performance test and for monitoring after the performance test. You shall:

(i) Install and operate a continuous parameter monitoring system to measure and record the hourly average volumetric air flow rate to the catalytic cracking unit or catalytic reforming unit regenerator. Or, you may determine and record the hourly average volumetric air flow rate to the catalytic cracking unit or catalytic reforming unit regenerator using the appropriate control room instrumentation.

(ii) Install and operate a continuous parameter monitoring system to measure and record the temperature of the gases entering the control device (or exiting the catalyst regenerator if you do not use an add-on control device).

(iii) Calculate and record the hourly average actual exhaust gas flow rate using Equation 1 of this section as follows:

$$Q_{gas} = (1.12\,\text{scfm}/\text{dscfm}) \times (Q_{air} + Q_{other}) \times \left(\frac{Temp_{gas}}{293^{\circ}K}\right) \times \left(\frac{1\text{atm.}}{P_{vent}}\right) \qquad \text{(Eq. 1)}$$

Where

Q_{gas} = Hourly average actual gas flow rate, acfm;

1.12 = Default correction factor to convert gas flow from dry standard cubic feet per minute (dscfm) to standard cubic feet per minute (scfm);

Q_{air} = Volumetric flow rate of air to regenerator, as determined from the control room instrumentations, dscfm;

Q_{other} = Volumetric flow rate of other gases entering the regenerator as determined from the control room instrumentations, dscfm. (Examples of "other" gases include an oxygen-enriched air stream to catalytic cracking unit regenerators and a nitrogen stream to catalytic reforming unit regenerators.);

$Temp_{gas}$ = Temperature of gas stream in vent measured as near as practical to the control device or opacity monitor, °K. For wet scrubbers, temperature of gas prior to the wet scrubber; and

P_{vent} = Absolute pressure in the vent measured as near as practical to the control device or opacity monitor, as applicable, atm. When used to assess the gas flow rate in the final atmospheric vent stack, you can assume P_{vent} = 1 atm.

(2) You may use this alternative to calculating Q_r, the volumetric flow rate of exhaust gas for the catalytic cracking regenerator as required in Equation 1 of §63.1564, if you have a gas analyzer installed in the catalytic cracking regenerator exhaust vent prior to the addition of air or other gas streams. You may measure upstream or downstream of an electrostatic precipitator, but you shall measure upstream of a carbon monoxide boiler. You shall:

(i) Install and operate a continuous parameter monitoring system to measure and record the hourly average volumetric air flow rate to the catalytic cracking unit regenerator. Or, you can determine and record the hourly average volumetric air flow rate to the catalytic cracking unit regenerator using the catalytic cracking unit control room instrumentation.

(ii) Install and operate a continuous gas analyzer to measure and record the concentration of carbon dioxide, carbon monoxide, and oxygen of the catalytic cracking regenerator exhaust.

(iii) Calculate and record the hourly average flow rate using Equation 2 of this section as follows:

$$Q_r = \frac{79 \times Q_{air} + (100 - \%O_{xy}) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. 2)}$$

Where:

Q_r = Volumetric flow rate of exhaust gas from the catalyst regenerator before adding air or gas streams, dscm/min (dscf/min);

79 = Default concentration of nitrogen and argon in dry air, percent by volume (dry basis);

$\%O_{xy}$ = Oxygen concentration in oxygen-enriched air stream, percent by volume (dry basis);

Q_{oxy} = Volumetric flow rate of oxygen-enriched air stream to regenerator as determined from the catalytic cracking unit control room instrumentations, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in regenerator exhaust, percent by volume (dry basis);

CO = Carbon monoxide concentration in regenerator exhaust, percent by volume (dry basis); and

$\%O_2$ = Oxygen concentration in regenerator exhaust, percent by volume (dry basis).

(c) *Can I use another type of monitoring system?* You may request approval from your permitting authority to use an automated data compression system. An automated data compression system does not record monitored operating parameter values at a set frequency (e.g., once every hour) but records all values that meet set criteria for variation from previously recorded values. Your request must contain a description of the monitoring system and data recording system, including the criteria used to determine which monitored values are recorded and retained, the method for calculating daily averages, and a demonstration that the system meets all of the criteria in paragraphs (c)(1) through (5) of this section:

(1) The system measures the operating parameter value at least once every hour;

(2) The system records at least 24 values each day during periods of operation;

(3) The system records the date and time when monitors are turned off or on;

(4) The system recognizes unchanging data that may indicate the monitor is not functioning properly, alerts the operator, and records the incident; and

(5) The system computes daily average values of the monitored operating parameter based on recorded data.

(e) *How do I request to monitor alternative parameters?* You must submit a request for review and approval or disapproval to the Administrator. The request must include the information in paragraphs (e)(1) through (5) of this section.

(1) A description of each affected source and the parameter(s) to be monitored to determine whether the affected source will continuously comply with the emission limitations and an explanation of the criteria used to select the parameter(s).

(2) A description of the methods and procedures that will be used to demonstrate that the parameter can be used to determine whether the affected source will continuously comply with the emission limitations and the schedule for this demonstration. You must certify that you will establish an operating limit for the monitored parameter(s) that represents the conditions in existence when the control device is being properly operated and maintained to meet the emission limitation.

(3) The frequency and content of monitoring, recording, and reporting, if monitoring and recording are not continuous. You also must include the rationale for the proposed monitoring, recording, and reporting requirements.

(4) Supporting calculations.

(5) Averaging time for the alternative operating parameter.

Notifications, Reports, and Records

§63.1574 What notifications must I submit and when?

(a) Except as allowed in paragraphs (a)(1) through (3) of this section, you must submit all of the notifications in §§63.6(h), 63.7(b) and (c), 63.8(e), 63.8(f)(4), 63.8(f)(6), and 63.9(b) through (h) that apply to you by the dates specified.

(1) You must submit the notification of your intention to construct or reconstruct according to §63.9(b)(5) unless construction or reconstruction had commenced and initial startup had not occurred before April 11, 2002. In this case, you must submit the notification as soon as practicable before startup but no later than July 10, 2002. This deadline also applies to the application for approval of construction or reconstruction and approval of construction or reconstruction based on State preconstruction review required in §§63.5(d)(1)(i) and 63.5(f)(2).

(2) You must submit the notification of intent to conduct a performance test required in §63.7(b) at least 30 calendar days before the performance test is scheduled to begin (instead of 60 days).

(3) If you are required to conduct a performance test, performance evaluation, design evaluation, opacity observation, visible emission observation, or other initial compliance demonstration, you must submit a notification of compliance status according to §63.9(h)(2)(ii). You can submit this information in an operating permit application, in an amendment to an operating permit application, in a separate submission, or in any combination. In a State with an approved operating permit program where delegation of authority under section 112(l) of the CAA has not been requested or approved, you must provide a duplicate notification to the applicable Regional Administrator. If the required information has been submitted previously, you do not have to provide a separate notification of compliance status. Just

refer to the earlier submissions instead of duplicating and resubmitting the previously submitted information.

(i) For each initial compliance demonstration that does not include a performance test, you must submit the Notification of Compliance Status no later than 30 calendar days following completion of the initial compliance demonstration.

(ii) For each initial compliance demonstration that includes a performance test, you must submit the notification of compliance status, including the performance test results, no later than 150 calendar days after the compliance date specified for your affected source in §63.1563.

(c) If you startup your new or reconstructed affected source on or after April 11, 2002, you must submit the initial notification no later than 120 days after you become subject to this subpart.

(d) You also must include the information in Table 42 of this subpart in your notification of compliance status.

(f) As required by this subpart, you must prepare and implement an operation, maintenance, and monitoring plan for each control system and continuous monitoring system for each affected source. The purpose of this plan is to detail the operation, maintenance, and monitoring procedures you will follow.

(1) You must submit the plan to your permitting authority for review and approval along with your notification of compliance status. While you do not have to include the entire plan in your part 70 or 71 permit, you must include the duty to prepare and implement the plan as an applicable requirement in your part 70 or 71 operating permit. You must submit any changes to your permitting authority for review and approval and comply with the plan until the change is approved.

(2) Each plan must include, at a minimum, the information specified in paragraphs (f)(2)(i) through (xii) of this section.

(i) Process and control device parameters to be monitored for each affected source, along with established operating limits.

(ii) Procedures for monitoring emissions and process and control device operating parameters for each affected source.

(iii) Procedures that you will use to determine the coke burn-rate, the volumetric flow rate (if you use process data rather than direct measurement), and the rate of combustion of liquid or solid fossil fuels if you use an incinerator-waste heat boiler to burn the exhaust gases from a catalyst regenerator.

(v) Procedures you will use to determine the pH of the water (or scrubbing liquid) exiting a wet scrubber if you use pH strips.

(vi) Procedures you will use to determine the HCl concentration of gases from a catalytic reforming unit when you use a colormetric tube sampling system, including procedures for correcting for pressure (if applicable to the sampling equipment) and the sampling locations that will be used for compliance monitoring purposes.

(vii) Procedures you will use to determine the gas flow rate for a catalytic cracking unit if you use the alternative procedure based on air flow rate and temperature.

(viii) Monitoring schedule, including when you will monitor and when you will not monitor an affected source (e.g., during the coke burn-off, regeneration process).

(ix) Quality control plan for each continuous opacity monitoring system and continuous emission monitoring system you use to meet an emission limit in this subpart. This plan must include procedures you will use for calibrations, accuracy audits, and adjustments to the system needed to meet applicable requirements for the system.

(x) Maintenance schedule for each monitoring system and control device for each affected source that is generally consistent with the manufacturer's instructions for routine and long-term maintenance.

§63.1575 What reports must I submit and when?

(a) You must submit each report in Table 43 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule, you must submit each report by the date in Table 43 of this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.1563 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your affected source in §63.1563.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.1563.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to §70.6(a)(3)(iii)(A) or §71.6(a)(3)(iii)(A) of this chapter, you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If there are no deviations from any emission limitation that applies to you and there are no deviations from the requirements for work practice standards, a statement that there were no deviations from the emission limitations or work practice standards during the reporting period and that no continuous emission monitoring system or continuous opacity monitoring system was inoperative, inactive, malfunctioning, out-of-control, repaired, or adjusted.

(d) For each deviation from an emission limitation and for each deviation from the requirements for work practice standards that occurs at an affected source where you are not using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation or work practice standard in this subpart, the compliance report must contain the information in paragraphs (c)(1) through (3) of this section and the information in paragraphs (d)(1) through (3) of this section.

(1) The total operating time of each affected source during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(3) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(e) For each deviation from an emission limitation occurring at an affected source where you are using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, you must include the information in paragraphs (d)(1) through (3) of this section and the information in paragraphs (e)(1) through (13) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was inoperative, except for zero (low-level) and high-level checks.

(3) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging period specified in the regulation for other types of emission limitations), and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period and into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging time specified in the regulation for other types of standards), and the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system as a percent of the total source operating time during that reporting period.

(8) A breakdown of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period into periods that are due to monitoring equipment malfunctions, non-monitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes.

(9) An identification of each HAP that was monitored at the affected source.

(10) A brief description of the process units.

(11) The monitoring equipment manufacturer(s) and model number(s).

(12) The date of the latest certification or audit for the continuous opacity monitoring system or continuous emission monitoring system.

(13) A description of any change in the continuous emission monitoring system or continuous opacity monitoring system, processes, or controls since the last reporting period.

(f) You also must include the information required in paragraphs (f)(1) through (2) of this section in each compliance report, if applicable.

(1) A copy of any performance test done during the reporting period on any affected unit. The report may be included in the next semiannual report. The copy must include a complete report for each test method used for a particular kind of emission point tested. For additional tests performed for a similar emission

point using the same method, you must submit the results and any other information required, but a complete test report is not required. A complete test report contains a brief process description; a simplified flow diagram showing affected processes, control equipment, and sampling point locations; sampling site data; description of sampling and analysis procedures and any modifications to standard procedures; quality assurance procedures; record of operating conditions during the test; record of preparation of standards; record of calibrations; raw data sheets for field sampling; raw data sheets for field and laboratory analyses; documentation of calculations; and any other information required by the test method.

(2) Any requested change in the applicability of an emission standard (e.g., you want to change from the PM standard to the Ni standard for catalytic cracking units or from the HCl concentration standard to percent reduction for catalytic reforming units) in your periodic report. You must include all information and data necessary to demonstrate compliance with the new emission standard selected and any other associated requirements.

(g) You may submit reports required by other regulations in place of or as part of the compliance report if they contain the required information.

(h) The reporting requirements in paragraphs (h)(1) and (2) of this section apply to startups, shutdowns, and malfunctions:

(1) When actions taken to respond are consistent with the plan, you are not required to report these events in the semiannual compliance report and the reporting requirements in §§63.6(e)(3)(iii) and 63.10(d)(5) do not apply.

(2) When actions taken to respond are not consistent with the plan, you must report these events and the response taken in the semiannual compliance report. In this case, the reporting requirements in §§63.6(e)(3)(iv) and 63.10(d)(5) do not apply.

§63.1576 What records must I keep, in what form, and for how long?

(a) You must keep the records specified in paragraphs (a)(1) through (3) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any initial notification or Notification of Compliance Status that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, performance evaluations, and opacity and visible emission observations as required in §63.10(b)(2)(viii).

(b) For each continuous emission monitoring system and continuous opacity monitoring system, you must keep the records required in paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Monitoring data for continuous opacity monitoring systems during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

(3) Previous (i.e., superceded) versions of the performance evaluation plan as required in §63.8(d)(3).

(4) Requests for alternatives to the relative accuracy test for continuous emission monitoring systems as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records in §63.6(h) for visible emission observations.

(d) You must keep records required by Tables 6, 7, 13, and 14 of this subpart (for catalytic cracking units); Tables 20, 21, 27 and 28 of this subpart (for catalytic reforming units); Tables 34 and 35 of this subpart (for sulfur recovery units); and Table 39 of this subpart (for bypass lines) to show continuous compliance with each emission limitation that applies to you.

(e) You must keep a current copy of your operation, maintenance, and monitoring plan onsite and available for inspection. You also must keep records to show continuous compliance with the procedures in your operation, maintenance, and monitoring plan.

(f) You also must keep the records of any changes that affect emission control system performance including, but not limited to, the location at which the vent stream is introduced into the flame zone for a boiler or process heater.

(g) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(h) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(i) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records offsite for the remaining 3 years.

Table 1 to Subpart UUU of Part 63—Metal HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1564(a)(1), you shall meet each emission limitation in the following table that applies to you.

For each new or existing catalytic cracking unit	You shall meet the following emission limits for each catalyst regenerator vent.
2. Option 1: NSPS requirements not subject to the NSPS for PM in 40 CFR 60.102.	PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period.

Table 2 to Subpart UUU of Part 63—Operating Limits for Metal HAP Emissions From Catalytic Cracking Units

As stated in §63.1564(a)(2), you shall meet each operating limit in the following table that applies to you.

For each new or existing catalytic cracking unit	For this type of continuous monitoring system	For this type of control device	You shall meet this operating limit
2. Option 1: NSPS requirements not subject to the NSPS for PM in 40 CFR 60.102.	Continuous opacity monitoring system.	Not applicable.	Not applicable.

Table 3 to Subpart UUU of Part 63—Continuous Monitoring Systems for Metal HAP Emissions From Catalytic Cracking Units

As stated in §63.1564(b)(1), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit	If your catalytic cracking unit is	And you use this type of control device for your vent	You shall install, operate, and maintain a
3. Option 2: PM limit not subject to the NSPS for PM in 40 CFR 60.102.	a. Over 20,000 barrels per day fresh feed capacity.	Electrostatic precipitator.	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent.

Table 4 to Subpart UUU of Part 63—Requirements for Performance Tests for Metal HAP Emissions From Catalytic Cracking Units Not Subject to the New Source Performance Standard (NSPS) for Particulate Matter (PM)

As stated in §63.1564(b)(2), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit catalyst regenerator vent	You must	Using	According to these requirements
1. If you elect Option 1 in item 2 of Table 1, Option 2 in item 3 of Table 1, Option 3 in item 4 of Table 1, or Option 4 in item 5 of Table 1 of this subpart.	a. Select sampling port's location and the number of traverse ports.	Method 1 or 1A in appendix A to part 60 of this chapter.	Sampling sites must be located at the outlet of the control device or the outlet of the regenerator, as applicable, and prior to any releases to the atmosphere.
	b. Determine velocity and volumetric flow rate.	Method 2, 2A, 2C, 2D, 2F, or 2G in appendix A to part 60 of this chapter, as applicable.	
	c. Conduct gas molecular weight analysis.	Method 3, 3A, or 3B in appendix A to part 60 of this chapter, as applicable.	
	d. Measure moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.	
	e. If you use an electro-static precipitator, record the total number of fields in the control system and how many operated during the applicable performance test.		
2. Option 1: Elect NSPS	a. Measure PM emissions.	Method 5B or 5F (40 CFR part 60, appendix A) to determine PM emissions and associated moisture content for units without wet scrubbers. Method 5B (40 CFR part 60, appendix A) to determine PM emissions and associated moisture content for unit with wet scrubber.	You must maintain a sampling rate of at least 0.15 dry standard cubic meters per minute (dscm/min) (0.53 dry standard cubic feet per minute (dscf/min).
	b. Compute PM emission rate (lbs/1,000 lbs) of coke burn-off.	Equations 1, 2, and 3 of §63.1564 (if applicable).	

For each new or existing catalytic cracking unit catalyst regenerator vent	You must	Using	According to these requirements
	c. Measure opacity of emissions.	Continuous opacity monitoring system.	You must collect opacity monitoring data every 10 seconds during the entire period of the Method 5B or 5F performance test and reduce the data to 6-minute averages.

Table 5 to Subpart UUU of Part 63—Initial Compliance With Metal HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1564(b)(5), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit catalyst regenerator vent	For the following emission limit	You have demonstrated initial compliance if
2. Option 1: Elect NSPS not subject to the NSPS for PM.	PM emission must not exceed 1.0 kg/ 1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period.	The average PM emission rate, measured using EPA Method 5B or 5F (for a unit without a wet scrubber) or 5B (for a unit with a wet scrubber), over the period of the initial performance test, is no higher than 1.0 kg/1,000 kg (1.0 lb/1,000 lb of coke burn-off in the catalyst regenerator. The PM emission rate is calculated using Equations 1 and 2 of §63.1564. If applicable, the average PM emission rate, measured using EPA Method 5B emission rate, measured using EPA Method 5B or 5F (for a unit without a wet scrubber) or Method 5B (for a unit with a wet scrubber) over the period of the initial performance test, is no higher than 43.0 g/GJ (0.10 lb/ million Btu) of heat input attributable to the liquid or solid fossil fuel. The PM emission rate is calculated using Equation 3 of §63.1564; no more than one 6-minute average measured by the continuous opacity monitoring system exceeds 30 percent opacity in any 1-hour period over the period of the performance test; and your performance evaluation shows the continuous opacity monitoring system meets the applicable requirements in §63.1572.

Table 6 to Subpart UUU of Part 63—Continuous Compliance With Metal HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1564(c)(1), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit	Subject to this emission limit for your catalyst regenerator vent	You shall demonstrate continuous compliance by
1. Subject to the NSPS for PM in 40 CFR 60.102.	a. PM emissions must not exceed 1.0 kg/ 1,000 kg (1.0 lb/ 1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/ million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period.	i. Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in §63.1564 and the hours of operation for each catalyst regenerator; maintaining PM emission rate below 1.0 kg/1,000 kg (1.0 lb/1,000 lbs) of coke burn-off; if applicable, determining and recording each day the rate of combustion of liquid or solid fossil fuels (liters/hour or kilograms/hour) and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator- waste heat boiler; if applicable, maintaining the PM rate incinerator below 43 g/GJ (0.10 lb/million Btu) of heat input attributable to the solid or liquid fossil fuel; collecting the continuous opacity monitoring data for each catalyst regenerator vent according to §63.1572; and maintaining each 6-minute average at or below 30 percent except that one 6- minute average during a 1-hour period can exceed 30 percent.
2. Option 1: Elect NSPS not subject to the NSPS for PM in 40 CFR 60.102.	See item 1.a. of this table.	See item 1.a.i. of this table.

Table 7 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Metal HAP Emissions From Catalytic Cracking Units

As stated in §63.1564(c)(1), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit	If you use	For this operating limit	You shall demonstrate continuous compliance by
2. Option 1: Elect NSPS not subject to the NSPS for PM in 40 CFR 60.102.	Continuous opacity monitoring system.	Not applicable.	Complying with Table 6 of this subpart.

Table 8 to Subpart UUU of Part 63—Organic HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1565(a)(1), you shall meet each emission limitation in the following table that applies to you.

For each new and existing catalytic cracking unit	You shall meet the following emission limit for each catalyst regenerator

For each new and existing catalytic cracking unit	You shall meet the following emission limit for each catalyst regenerator
2. Not subject to the NSPS for CO in 40 CFR 60.103	a. CO emissions from the catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).

Table 9 to Subpart UUU of Part 63—Operating Limits for Organic HAP Emissions From Catalytic Cracking Units

As stated in §63.1565(a)(2), you shall meet each operating limit in the following table that applies to you.

For each new or existing catalytic cracking unit	For this type of continuous monitoring system	For this type of control device	You shall meet this operating limit
2. Not subject to the NSPS for CO in 40 CFR 60.103.	a. Continuous emission monitoring system.	Not applicable	Not applicable.

Table 10 to Subpart UUU of Part 63—Continuous Monitoring Systems for Organic HAP Emissions From Catalytic Cracking Units

As stated in §63.1565(b)(1), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit	And you use this type of control device for your vent	You shall install, operate, and maintain this type of continuous monitoring system
2. Not subject to the NSPS for CO in 40 CFR 60.103.	D. No control device	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent.

Table 11 to Subpart UUU of Part 63—Requirements for Performance Tests for Organic HAP Emissions From Catalytic Cracking Units Not Subject to New Source Performance Standard (NSPS) for Carbon Monoxide (CO)

As stated in §63.1565(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For	You must	Using	According to these requirements
1. Each new or existing catalytic cracking unit catalyst regenerator vent.	a. Select sampling port's location and the number of traverse ports.	Method 1 or 1A in appendix A to part 60 of this chapter.	Sampling sites must be located at the outlet of the control device or the outlet of the regenerator, as applicable, and prior to any releases to the atmosphere.
	b. Determine velocity and volumetric flow rate.	Method 2, 2A, 2D, 2F, or 2G in appendix A to part 60 of this chapter, as applicable.	

For	You must	Using	According to these requirements
	c. Conduct gas molecular weight analysis.	Method 3, 3A, or 3B in appendix A to part 60 of this chapter, as applicable.	
	d. Measure moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.	
2. For each new or existing catalytic cracking unit catalyst regenerator vent if you use a continuous emission monitoring system.	Measure CO emissions	Data from your continuous emission monitoring system.	Collect CO monitoring data for each vent for 24 consecutive operating hours; and reduce the continuous emission monitoring data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period.

Table 12 to Subpart UUU of Part 63—Initial Compliance With Organic HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1565(b)(4), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit	For the following emission limit	You have demonstrated initial compliance if
2. Not subject to the NSPS for CO in 40 CFR 60.103.	a. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	ii. If you use a continuous emission monitoring system, the hourly average CO emissions over the 24-hour period for the initial performance test are not more than 500 ppmv (dry basis); and your performance evaluation shows your continuous emission monitoring system meets the applicable requirements in §63.1572.

Table 13 to Subpart UUU of Part 63—Continuous Compliance With Organic HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1565(c)(1), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit	Subject to this emission limit for your catalyst regenerator vent	If you must	You shall demonstrate continuous compliance by
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103.	CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	Continuous emission monitoring system.	Collecting the hourly average CO monitoring data according to §63.1572; and maintaining the hourly average CO concentration at or below 500 ppmv (dry basis).

For each new and existing catalytic cracking unit	Subject to this emission limit for your catalyst regenerator vent	If you must	You shall demonstrate continuous compliance by
2. Not subject to the NSPS for CO in 40 CFR 60.103.	i. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	Continuous emission monitoring system.	Same as above.

Table 14 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Organic HAP Emissions From Catalytic Cracking Units

As stated in §63.1565(c)(1), you shall meet each requirement in the following table that applies to you.

For each new existing catalytic cracking unit	If you use	For this operating limit	You shall demonstrate continuous compliance by
2. Not subject to the NSPS for CO in 40 CFR 60.103.	a. Continuous emission monitoring system.	Not applicable	Complying with Table 13 of this subpart.

Table 15 to Subpart UUU of Part 63—Organic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1566(a)(1), you shall meet each emission limitation in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit	You shall meet this emission limit during initial catalyst depressuring and catalyst purging operations
1. Option 1	Vent emissions to a flare that meets the requirements for control devices in §63.11(b). Visible emissions from a flare must not exceed a total of 5 minutes during any 2-hour operating period.

Table 16 to Subpart UUU of Part 63—Operating Limits for Organic HAP Emissions From Catalytic Reforming Units

As stated in §63.1566(a)(2), you shall meet each operating limit in the following table that applies to you.

For each new or existing catalytic reforming unit	For this type of control device	You shall meet this operating limit during initial catalyst depressuring and purging operations
1. Option 1: vent to flare.	Flare that meets the requirements for control devices in §63.11(b).	The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it.

Table 17 to Subpart UUU of Part 63—Continuous Monitoring Systems for Organic HAP Emissions From Catalytic Reforming Units

As stated in §63.1566(b)(1), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit	If you use this type of control device	You shall install and operate this type of continuous monitoring system
1. Option 1: vent to a flare	Flare that meets the requirements for control devices in §63.11(b).	Monitoring device such as a thermocouple, an ultraviolet beam sensor, or infrared sensor to continuously detect the presence of a pilot flame.

Table 18 to Subpart UUU of Part 63—Requirements for Performance Tests for Organic HAP Emissions From Catalytic Reforming Units

As stated in §63.1566(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For each new or exiting catalytic reforming unit	You must	Using	According to these requirements
1. Option 1: Vent to a flare	a. Conduct visible emission observations. b. Determine that the flare meets the requirements for net heating value of the gas being combusted and exit velocity.	Method 22 (40 CFR part 60, appendix A). Not applicable.	2-hour observation period. Record the presence of a flame at the pilot light over the full period of the test. 40 CFR 63.11(b)(6) through (8).

Table 19 to Subpart UUU of Part 63—Initial Compliance With Organic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1566(b)(7), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit	For the following emission limit	You have demonstrated initial compliance if
Option 1	Visible emissions from a flare must not exceed a total of 5 minutes during any 2 consecutive hours.	Visible emissions, measured using Method 22 over the 2-hour observation period of the performance test, do not exceed a total of 5 minutes.

Table 20 to Subpart UUU of Part 63—Continuous Compliance With Organic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1566(c)(1), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit	For this emission limit	You shall demonstrate continuous compliance during initial catalyst depressuring and catalyst purging operations by
1. Option 1	Vent emissions from your process vent to a flare that meets the requirements in §63.11(b).	Maintaining visible emissions from a flare below a total of 5 minutes during any 2 consecutive hours.

Table 21 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Organic HAP Emissions From Catalytic Reforming Units

As stated in §63.1566(c)(1), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit	If you use	For this operating limit	You shall demonstrate continuous compliance during initial catalyst depressuring and purging operations by
1. Option 1	Flare that meets the requirements in §63.11(b).	The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it.	Collecting flare monitoring data according to §63.1572; and recording for each 1-hour period whether the monitor was continuously operating and the pilot light was continuously present during each 1-hour period.

Table 22 to Subpart UUU of Part 63—Inorganic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1567(a)(1), you shall meet each emission limitation in the following table that applies to you.

For	You shall meet this emission limit for each applicable catalytic reforming unit process vent during coke burn- off and catalyst rejuvenation
2. Each existing cyclic or continuous catalytic reforming unit.	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.

Table 23 to Subpart UUU of Part 63—Operating Limits for Inorganic HAP Emission Limitations for Catalytic Reforming Units

As stated in §63.1567(a)(2), you shall meet each operating limit in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit with this type of control device	You shall meet this operating limit during coke burn-off and catalyst rejuvenation
1. Wet scrubber	The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber must not fall below the limit established during the performance test; and the daily average liquid-to-gas ratio must not fall below the limit established during the performance test.
3. Internal scrubbing system meeting HCl percent reduction standard.	The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system must not fall below the limit established during the performance test; and the daily average liquid-to-gas ratio must not fall below the limit established during the performance test.

Table 24 to Subpart UUU of Part 63—Continuous Monitoring Systems for Inorganic HAP Emissions From Catalytic Reforming Units

As stated in §63.1567(b)(1), you shall meet each requirement in the following table that applies to you.

If you use this type of control device for your vent	You shall install and operate this type of continuous monitoring system
1. Wet scrubber	Continuous parameter monitoring system to measure and record the total water (or scrubbing liquid) flow rate entering the scrubber during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record gas flow rate entering or exiting the scrubber during coke burn-off and catalyst rejuvenation \1\; and continuous parameter monitoring system to measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation. \2\
3. Internal scrubbing system to meet HC1 percent reduction standard.	Continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record the total water (or scrubbing liquid) flow rate entering the internal scrubbing system during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation. \2\
\1\ If applicable, you can use the alternative in §63.1573 (a)(1) instead of a continuous parameter monitoring system for gas flow rate or instead of a continuous parameter monitoring system for the cumulative volume of gas. \2\ If applicable, you can use the alternative in §63.1573(b)(1) instead of a continuous parameter monitoring system for pH of the water (or scrubbing liquid) or the alternative in §63.1573(b)(2) instead of a continuous parameter monitoring system for alkalinity of the water (or scrubbing liquid).	

Table 25 to Subpart UUU of Part 63—Requirements for Performance Tests for Inorganic HAP Emissions From Catalytic Reforming Units

As stated in §63.1567(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic reforming unit using	You shall	Using	According to these requirements
1. Any or no control system	a. Select sampling port location(s) and the number of traverse points.	Method 1 or 1A (40 CFR part 60, appendix A), as applicable.	(1) If you operate a control device and you elect to meet an applicable HCl percent reduction standard, sampling sites must be located at the inlet of the control device or internal scrubbing system and at the outlet of the control device or internal scrubber system prior to any release to the atmosphere. For a series of fixed-bed systems, the outlet sampling site should be located at the outlet of the first fixed- bed, prior to entering the second fixed-bed in the series. (2) If you elect to meet an applicable HCl outlet concentration limit, locate sampling sites at the outlet of the control device or internal scrubber system prior to any release to the atmosphere. For a series of fixed-bed systems, the outlet sampling site should be located at the outlet of the first fixed- bed, prior to entering the second fixed-bed in the series. If there is no control device, locate sampling sites at the outlet of the catalyst regenerator prior to any release to the atmosphere.
	b. Determine velocity and volumetric flow rate.	Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A), as applicable.	
	c. Conduct gas molecular weight analysis.	Method 3, 3A, or 3B (40 CFR part 60, appendix A), as applicable.	
	d. Measure moisture content of the stack gas.	Method 4 (40 CFR part 60, appendix A).	

For each new and existing catalytic reforming unit using	You shall	Using	According to these requirements
	e. Measure the HCl concentration at the selected sampling locations.	Method 26 or 26A (40 CFR part 60, appendix A). If your control device is a wet scrubber or internal scrubbing system, you must use Method 26A.	(1) For semi-regenerative and cyclic regeneration units, conduct the test during the coke burn-off and catalyst rejuvenation cycle, but collect no samples during the first hour or the last 6 hours of the cycle (for semi-regenerative units) or during the first hour or the last 2 hours of the cycle (for cyclic regeneration units). For continuous regeneration units, the test should be conducted no sooner than 3 days after process unit or control system start up. (2) Determine and record the HCl concentration corrected to 3 percent oxygen (using Equation 1 of §63.1567) for each sampling location for each test run. (3) Determine and record the percent emission reduction, if applicable, using Equation 3 of §63.1567 for each test run. (4) Determine and record the average HCl concentration (corrected to 3 percent oxygen) and the average percent emission reduction, if applicable, for the overall source test from the recorded test run values.
2. Wet scrubber	a. Establish operating limit for pH level or alkalinity.	i. Data from continuous parameter monitoring systems.	Measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting scrubber every 15 minutes during the entire period of the performance test. Determine and record the minimum hourly average pH or alkalinity level from the recorded values.
		ii. Alternative pH procedure in §63.1573 (b)(1).	Measure and record the pH of the water (or scrubbing liquid) exiting the scrubber during coke burn- off and catalyst rejuvenation using pH strips at least three times during each test run. Determine and record the average pH level for each test run. Determine and record the minimum test run average pH level.
		iii. Alternative alkalinity method in §63.1573(b)(2).	Measure and record the alkalinity of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation using discrete titration at least three times during each test run. Determine and record the average alkalinity level for each test run. Determine and record the minimum test run average alkalinity level.
	b. Establish operating limit for liquid-to-gas ratio.	i. Data from continuous parameter monitoring systems.	Measure and record the gas flow rate entering or exiting the scrubber and the total water (or scrubbing liquid) flow rate entering the scrubber every 15 minutes during the entire period of the performance test. Determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate. Determine and record the minimum liquid-to-gas ratio from the recorded, paired values.

For each new and existing catalytic reforming unit using	You shall	Using	According to these requirements
		ii. Alternative procedure for gas flow rate in §63.1573(a)(1).	Collect air flow rate monitoring data or determine the air flow rate using control room instruments every 15 minutes during the entire period of the initial performance test. Determine and record the hourly average rate of all the readings. Determine and record the maximum gas flow rate using Equation 1 of §63.1573.
4. Internal scrubbing system meeting HCl percent reduction standard.	a. Establish operating limit for pH level or alkalinity.	i. Data from continuous parameter monitoring system.	Measure and record the pH alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system every 15 minutes during the entire period of the performance test. Determine and record the minimum hourly average pH or alkalinity level from the recorded values.
		ii. Alternative pH method in §63.1573(b)(1).	Measure and in record pH of the water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation using pH strips at least three times during each test run. Determine and record the average pH level for each test run. Determine and record the minimum test run average pH level.
		iii. Alternative alkalinity method in §63.1573(b)(2).	Measure and record the alkalinity water (or scrubbing liquid) exiting the internal scrubbing system during coke burn- off and catalyst rejuvenation using discrete titration at least three times during each test run. Determine and record the average alkalinity level for each test run. Determine and record the minimum test run average alkalinity level.
	b. Establish operating limit for liquid-to-gas ratio.	Data from continuous parameter monitoring systems.	Measure and record the gas entering or exiting the internal scrubbing system and the total water (or scrubbing liquid) flow rate entering the internal scrubbing system every 15 minutes during the entire period of the performance test. Determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate. Determine and record the minimum liquid-to-gas ratio from the recorded, paired values.

Table 26 to Subpart UUU of Part 63—Initial Compliance With Inorganic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1567(b)(4), you shall meet each requirement in the following table that applies to you.

For	For the following emission limit	You have demonstrated initial compliance if
2. Each existing cyclic or continuous catalytic reforming unit and each new semi- regenerative, cyclic, or continuous catalytic reforming unit.	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.	Average emissions of HCl measured using Method 26 or 26A, as applicable, over the period of the performance test, are reduced by 97 percent or to a concentration less than or equal to 10 ppmv (dry basis) corrected to 3 percent oxygen.

Table 27 to Subpart UUU of Part 63—Continuous Compliance With Inorganic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1567(c)(1), you shall meet each requirement in the following table that applies to you.

For	For this emission limit	You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by
2. Each existing cyclic or continuous catalytic reforming unit.	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.	Maintaining a 97 percent HCl control efficiency or an HCl concentration no more than 10 ppmv (dry basis), corrected to 3 percent oxygen.

Table 28 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Inorganic HAP Emissions From Catalytic Reforming Units

As stated in §63.1567(c)(1), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic reforming unit using this type of control device or system	For this operating limit	You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by
1. Wet scrubber	a. The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber must not fall below the level established during the performance test.	Collecting the hourly and daily average pH or alkalinity monitoring data according to 63.1572 \1\; and maintaining the daily average pH or alkalinity above the operating limit established during the performance test.
	b. The daily average liquid-to-gas ratio must not fall below the level established during the performance test.	Collecting the hourly average gas flow rate \2\ and total water (or scrubbing liquid) flow rate monitoring data according to 63.1572; and determining and recording the hourly average liquid-to-gas ratio; and determining and recording the daily average liquid-to- gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test.
3. Internal scrubbing system meeting percent HCl reduction standard.	a. The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system must not fall below the limit established during the performance test.	Collecting the hourly and daily average pH or alkalinity monitoring data according to 63.1572 \1\ and maintaining the daily average pH or alkalinity above the operating limit established during the performance test.
	b. The daily average liquid-to-gas ratio must not fall below the level established during the performance test.	Collecting the hourly average gas flow rate \2\ and total water (or scrubbing liquid) flow rate monitoring data according to 63.1572; and determining and recording the hourly average liquid-to-gas ratio; and determining and recording the daily average liquid-to- gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test.

For each new and existing catalytic reforming unit using this type of control device or system	For this operating limit	You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by
\1\ If applicable, you can use either alternative in §63.1573(b) instead of a continuous parameter monitoring system for pH or alkalinity if you used the alternative method in the initial performance test. \2\ If applicable, you can use the alternative in §63.1573(a)(1) instead of a continuous parameter monitoring system for the gas flow rate or cumulative volume of gas entering or exiting the system if you used the alternative method in the initial performance test.		

Table 29 to Subpart UUU of Part 63—HAP Emission Limits for Sulfur Recovery Units

As stated in §63.1568(a)(1), you shall meet each emission limitation in the following table that applies to you.

For	You shall meet this emission limit for each process vent
1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	a. 250 ppmv (dry basis) of sulfur dioxide (SO_2) at zero percent excess air if you use an oxidation or reduction control system followed by incineration.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air if you use a reduction control system without incineration.

Table 30 to Subpart UUU of Part 63—Operating Limits for HAP Emissions From Sulfur Recovery Units

As stated in §63.1568(a)(2), you shall meet each operating limit in the following table that applies to you.

For	If use this type of control device	You shall meet this operating limit
1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	Not applicable.	Not applicable.

Table 31 to Subpart UUU of Part 63—Continuous Monitoring Systems for HAP Emissions From Sulfur Recovery Units

As stated in §63.1568(b)(1), you shall meet each requirement in the following table that applies to you.

For	For this limit	You shall install and operate this continuous monitoring system
1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air if you use an oxidation or reduction control system followed by incineration.	Continuous emission monitoring system to measure and record the hourly average concentration of SO_2 (dry basis) at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air.

For	For this limit	You shall install and operate this continuous monitoring system
for sulfur oxides in 40 CFR 60.104(a)(2).	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air if you use a reduction control system without incineration.	Continuous emission monitoring system to measure and record the hourly average concentration of reduced sulfur and oxygen (O_2) emissions. Calculate the reduced sulfur emissions as SO_2 (dry basis) at zero percent excess air. Exception: You can use an instrument having an air or SO_2 dilution and oxidation system to convert the reduced sulfur to SO_2 for continuously monitoring and recording the concentration (dry basis) at zero percent excess air of the resultant SO_2 instead of the reduced sulfur monitor. The monitor must include an oxygen monitor for correcting the data for excess oxygen.

Table 33 to Subpart UUU of Part 63—Initial Compliance With HAP Emission Limits for Sulfur Recovery Units

As stated in §63.1568(b)(5), you shall meet each requirement in the following table that applies to you.

For	For the following emission limit	You have demonstrated initial compliance if
1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40CFR60.104(a)(2).	a. 250 ppmv (dry basis) SO_2 at zero percent excess air if you use an oxidation or reduction control system followed by incineration.	You have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12- hour rolling average concentration of SO_2 emissions measured by the continuous emission monitoring system is less than or equal to 250 ppmv (dry basis) at zero percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the SO_2 limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in 63.1572. You are not required to do another performance evaluation to demonstrate initial compliance.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air if you use a reduction control system without incineration.	You have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12- hour rolling average concentration of reduced sulfur compounds measured by your continuous emission monitoring system is less than or equal to 300 ppmv, calculated as ppmv SO_2 (dry basis) at zero percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the SO_2 limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in 63.1572. You are not required to do another performance evaluation to demonstrate initial compliance.

Table 34 to Subpart UUU of Part 63—Continuous Compliance With HAP Emission Limits for Sulfur Recovery Units

As stated in §63.1568(c)(1), you shall meet each requirement in the following table that applies to you.

For	For this emission limit	You shall demonstrate continuous compliance by
1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air if you use an oxidation or reduction control system followed by incineration.	Collecting the hourly average SO_2 monitoring data (dry basis, percent excess air) according to §63.1572; determining and recording each 12- hour rolling average concentration of SO_2; maintaining each 12-hour rolling average concentration of SO_2 at or below the applicable emission limitation; and reporting any 12- hour rolling average concentration of SO_2 greater than the applicable emission limitation in the compliance report required by §63.1575.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air if you use a reduction control system without incineration.	Collecting the hourly average reduced sulfur (and air or O_2 dilution and oxidation) monitoring data according to §63.1572; determining and recording each 12- hour rolling average concentration of reduced sulfur; maintaining each 12- hour rolling average concentration of reduced sulfur at or below the applicable emission limitation; and reporting any 12- hour rolling average concentration of reduced sulfur greater than the applicable emission limitation in the compliance report required by §63.1575.

Table 35 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for HAP Emissions From Sulfur Recovery Units

As stated in §63.1568(c)(1), you shall meet each requirement in the following table that applies to you.

For	For this operating limit	You shall demonstrate continuous compliance by
1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in paragraph 40 CFR 60.104(a)(2).	Not applicable	Meeting the requirements of Table 34 of this subpart.

Table 36 to Subpart UUU of Part 63—Work Practice Standards for HAP Emissions From Bypass Lines

As stated in §63.1569(a)(1), you shall meet each work practice standard in the following table that applies to you.

Option	You shall meet one of these equipment standards
1. Option 1	Install and operate a device (including a flow indicator, level recorder, or electronic valve position monitor) to demonstrate, either continuously or at least every hour, whether flow is present in the by bypass line. Install the device at or as near as practical to the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.

Table 37 to Subpart UUU of Part 63—Requirements for Performance Tests for Bypass Lines

As stated in §63.1569(b)(1), you shall meet each requirement in the following table that applies to you.

For this standard	You shall
1. Option 1: Install and operate a flow indicator, level recorder, or electronic valve position monitor.	Record during the performance test for each type of control device whether the flow indicator, level recorder, or electronic valve position monitor was operating and whether flow was detected at any time during each hour of level the three runs comprising the performance test.

Table 38 to Subpart UUU of Part 63—Initial Compliance With Work Practice Standards for HAP Emissions from Bypass Lines

As stated in §63.1569(b)(2), you shall meet each requirement in the following table that applies to you.

Option	For this work practice standard	You have demonstrated initial compliance if
1. Each new or existing bypass line associated with a catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit.	a. Option 1: Install and operate a device (including a flow indicator, level recorder, or electronic valve position monitor) to demonstrate, either continuously or at least every hour, whether flow is present in bypass line. Install the device at or as near as practical to the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.	The installed equipment operates properly during each run of the performance test and no flow is present in the line during the test.

Table 39 to Subpart UUU of Part 63—Continuous Compliance With Work Practice Standards for HAP Emissions From Bypass Lines

As stated in §63.1569(c)(1), you shall meet each requirement in the following table that applies to you.

If you elect this standard	You shall demonstrate continuous compliance by
1. Option 1: Flow indicator, level recorder, or electronic valve position monitor.	Monitoring and recording on a continuous basis or at least every hour whether flow is present in the bypass line; visually inspecting the device at least once every hour if the device is not equipped with a recording system that provides a continuous record; and recording whether the device is operating properly and whether flow is present in the bypass line.
5. Option 1, 2, 3, or 4	Recording and reporting the time and duration of any bypass.

Table 40 to Subpart UUU of Part 63—Requirements for Installation, Operation, and Maintenance of Continuous Opacity Monitoring Systems and Continuous Emission Monitoring Systems

As stated in §63.1572(a)(1) and (b)(1), you shall meet each requirement in the following table that applies to you.

This type of continuous opacity or emission monitoring system	Must meet these requirements
1. Continuous opacity monitoring system	Performance specification 1 (40 CFR part 60, appendix B).

This type of continuous opacity or emission monitoring system	Must meet these requirements
2. CO continuous emission monitoring system.	Performance specification 4 (40 CFR part 60, appendix B); span value of 1,000 ppm; and procedure 1 (40 CFR part 60, appendix F) except relative accuracy test audits are required annually instead of quarterly.
3. CO continuous emission monitoring system used to demonstrate emissions average under 50 ppm (dry basis).	Performance specification 4 (40 CFR part 60, appendix B); and span value of 100 ppm.
4. SO_2 continuous emission monitoring system for sulfur recovery unit with oxidation control system or reduction control system; this monitor must include an O_2 monitor for correcting the data for excess air.	Performance specification 2 (40 CFR part 60, appendix B); span value of 500 ppm SO_2; use Methods 6 or 6C and 3A or 3B (40 CFR part 60, appendix A) for certifying O_2 monitor; and procedure 1 (40 CFR part 60, appendix F) except relative accuracy test audits are required annually instead of quarterly.
5. Reduced sulfur and O_2 continuous emission monitoring system for sulfur recovery unit with reduction control system not followed by incineration; this monitor must include an O_2 monitor for correcting the data for excess air unless exempted.	Performance specification 5 (40 CFR part 60, appendix B), except calibration drift specification is 2.5 percent of the span value instead of 5 percent; 450 ppm reduced sulfur; use Methods 15 or 15A and 3A or 3B (40 CFR part 60, appendix A) for certifying O_2 monitor; if Method 3A or 3B yields O_2 concentrations below 0.25 percent during the performance evaluation, the O_2 concentration can be assumed to be zero and the O_2 monitor is not required; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.
6. Instrument with an air or O_2 dilution and oxidation system to convert reduced sulfur to SO_2 for continuously monitoring the concentration of SO_2 instead of reduced sulfur monitor and O_2 monitor.	Performance specification 5 (40 CFR part 60, appendix B); span value of 375 ppm SO_2; use Methods 15 or 15A and 3A or 3B for certifying O_2 monitor; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.
7. TRS continuous emission monitoring system for sulfur recovery unit; this monitor must include an O_2 monitor for correcting the data for excess air. 8. O_2 monitor for oxygen concentration.	Performance specification 5 (40 CFR part 60, appendix B). If necessary due to interferences, locate the oxygen sensor prior to the introduction of any outside gas stream; performance specification 3 (40 CFR part 60, appendix B; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.

Table 42 to Subpart UUU of Part 63—Additional Information for Initial Notification of Compliance Status

As stated in §63.1574(d), you shall meet each requirement in the following table that applies to you.

For	You shall provide this additional information
1. Identification of affected sources and emission points.	Nature, size, design, method of operation, operating design capacity of each affected source; identify each emission point for each HAP; identify any affected source or vent associated with an affected source not subject to the requirements of subpart UUU.
2. Initial compliance	Identification of each emission limitation you will meet for each affected source, including any option you select (i.e., NSPS, PM or Ni, flare, percent reduction, concentration, options for bypass lines); if applicable, certification that you have already conducted a performance test to demonstrate initial compliance with the NSPS for an affected source; certification that the vents meet the applicable emission limit and the continuous opacity or that the emission monitoring system meets the applicable performance specification; if applicable, certification that you have installed and verified the operational status of equipment by your compliance date for each bypass line that meets the requirements of Option 2, 3, or 4 in §63.1569 and what equipment you installed; identification of the operating limit for each affected source, including supporting documentation; if your affected source is subject to the NSPS, certification of compliance with NSPS emission limitations and performance specifications; a brief description of performance test conditions (capacity, feed quality, catalyst, etc.); an engineering assessment (if applicable); and if applicable, the flare design (e.g., steam-assisted, air-assisted, or non-assisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the Method 22 test.
3. Continuous compliance	Each monitoring option you elect; and identification of any unit or vent for which monitoring is not required; and the definition of ``operating day." (This definition, subject to approval by the applicable permitting authority, must specify the times at which a 24-hr operating day begins and ends.)

Table 43 to Subpart UUU of Part 63—Requirements for Reports

As stated in §63.1575(a), you shall meet each requirement in the following table that applies to you.

You must submit a(n)	The report must contain	You shall submit the report
1. Compliance report	If there are not deviations from any emission limitation or work practice standard that applies to you, a statement that there were no deviations from the standards during the reporting period and that no continuous opacity monitoring system or continuous emission monitoring system was inoperative, inactive, out-of-control, repaired, or adjusted; and if you have a deviation from any emission limitation or work practice standard during the reporting period, the report must contain the information in §63.1575(d) or (e)	Semiannually according to the requirements in §63.1575(b).

SECTION E.11 Nitrogen Oxides Budget Trading Program - NO_x Budget Permit for NO_x Budget Units Under 326 IAC 10-4-1(a)

ORIS Code: 52130

NO_x Budget Source [326 IAC 2-7-5(15)]

(w) A portion of No. 1 Stanolind Power Station (SPS) constructed in 1928 and identified as Unit ID 501. The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas, are NO_x budget units:

Boiler Identification	Installation Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
#3 Boiler (also known as 1SPS13)	1928	265	501-01	none
#4 Boiler (also known as 1SPS14)	1928	265	501-01	none
#5 Boiler (also known as 1SPS15)	1928	265	501-02	none
#6 Boiler (also known as 1SPS16)	1928	265	501-02	none
#7 Boiler (also known as 1SPS17)	1928	265	501-02	none

(x) A portion of No. 3 Stanolind Power Station (SPS), constructed as listed below and identified as Unit ID 503. The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas, are NO_x budget units:

Boiler Identification	Installation Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
#1 Boiler (also known as 3SPS31)	1948	575	503-01	low-NO_x burners, an induced flue gas recirculation (IFGR) system, and an over fired air (OFA) system
#2 Boiler (also known as 3SPS32)	1948	575	503-02	
#3 Boiler (also known as 3SPS33)	1951	575	503-03	
#4 Boiler (also known as 3SPS34)	1951	575	503-04	
#6 Boiler (also known as 3SPS36)	1953	575	503-05	

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

E.11.1 Automatic Incorporation of Definitions [326 IAC 10-4-7(e)]

This NO_x budget permit is deemed to incorporate automatically the definitions of terms under 326 IAC 10-4-2.

E.11.2 Standard Permit Requirements [326 IAC 10-4-4(a)]

(a) The owners and operators of the NO_x budget source and each NO_x budget unit shall operate each unit in compliance with this NO_x budget permit.

(b) The NO_x budget units subject to this NO_x budget permit include the following:

(1) At No. 1 Stanolind Power Station (SPS) and Boiler Water Treating Plant, #3 Boiler, #4 Boiler, #5 Boiler, #6 Boiler, and #7 Boiler; and

(2) At No. 3 Stanolind Power Station (SPS) and Boiler Water Treating Plant, #1 Boiler, #2 Boiler, #3 Boiler, #4 Boiler, and #6 Boiler.

E.11.3 Monitoring Requirements [326 IAC 10-4-4(b)]

(a) The owners and operators and, to the extent applicable, the NO_x authorized account representative of the NO_x budget source and each NO_x budget unit at the source shall comply with the monitoring requirements of 40 CFR 75 and 326 IAC 10-4-12.

(b) The emissions measurements recorded and reported in accordance with 40 CFR 75 and 326 IAC 10-4-12 shall be used to determine compliance by each unit with the NO_x budget emissions limitation under 326 IAC 10-4-4(c) and Condition E.11.4, Nitrogen Oxides Requirements.

E.11.4 Nitrogen Oxides Requirements [326 IAC 10-4-4(c)]

(a) The owners and operators of the NO_x budget source and each NO_x budget unit at the source shall hold NO_x allowances available for compliance deductions under 326 IAC 10-4-10(j), as of the NO_x allowance transfer deadline, in each unit's compliance account and the source's overdraft account in an amount:

(1) Not less than the total NO_x emissions for the ozone control period from the unit, as determined in accordance with 40 CFR 75 and 326 IAC 10-4-12;

(2) To account for excess emissions for a prior ozone control period under 326 IAC 10-4-10(k)(5); or

(3) To account for withdrawal from the NO_x budget trading program, or a change in regulatory status of a NO_x budget opt-in unit.

(b) Each ton of NO_x emitted in excess of the NO_x budget emissions limitation shall constitute a separate violation of the Clean Air Act (CAA) and 326 IAC 10-4.

(c) Each NO_x budget unit shall be subject to the requirements under (a) above and 326 IAC 10-4-4(c)(1) starting on May 31, 2004.

(d) NO_x allowances shall be held in, deducted from, or transferred among NO_x allowance tracking system accounts in accordance with 326 IAC 10-4-9 through 11, 326 IAC 10-4-13, and 326 IAC 10-4-14.

(e) A NO_x allowance shall not be deducted, in order to comply with the requirements under (a) above and 326 IAC 10-4-4(c)(1), for an ozone control period in a year prior to the year for which the NO_x allowance was allocated.

(f) A NO_x allowance allocated under the NO_x budget trading program is a limited authorization to emit one (1) ton of NO_x in accordance with the NO_x budget trading program. No provision of the NO_x budget trading program, the NO_x budget permit application, the NO_x budget permit, or an exemption under 326 IAC 10-4-3 and no provision of law shall be construed to limit the authority of the U.S. EPA or IDEM, OAQ to terminate or limit the authorization.

(g) A NO_x allowance allocated under the NO_x budget trading program does not constitute a property right.

(h) Upon recordation by the U.S. EPA under 326 IAC 10-4-10, 326 IAC 10-4-11, or 326 IAC 10-4-13, every allocation, transfer, or deduction of a NO_x allowance to or from each NO_x budget unit's compliance account or the overdraft account of the source where

the unit is located is deemed to amend automatically, and become a part of, this NO_x budget permit of the NO_x budget unit by operation of law without any further review.

E.11.5 Excess Emissions Requirements [326 IAC 10-4-4(d)]

The owners and operators of each NO_x budget unit that has excess emissions in any ozone control period shall do the following:

(a) Surrender the NO_x allowances required for deduction under 326 IAC 10-4-10(k)(5).

(b) Pay any fine, penalty, or assessment or comply with any other remedy imposed under 326 IAC 10-4-10(k)(7).

E.11.6 Record Keeping Requirements [326 IAC 10-4-4(e)] [326 IAC 2-7-5(3)]

Unless otherwise provided, the owners and operators of the NO_x budget source and each NO_x budget unit at the source shall keep, either on site at the source or at a central location within Indiana for those owners or operators with unattended sources, each of the following documents for a period of five (5) years:

(a) The account certificate of representation for the NO_x authorized account representative for the source and each NO_x budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with 326 IAC 10-4-6(h). The certificate and documents shall be retained either on site at the source or at a central location within Indiana for those owners or operators with unattended sources beyond the five (5) year period until the documents are superseded because of the submission of a new account certificate of representation changing the NO_x authorized account representative.

(b) All emissions monitoring information, in accordance with 40 CFR 75 and 326 IAC 10-4-12, provided that to the extent that 40 CFR 75 and 326 IAC 10-4-12 provide for a three (3) year period for record keeping, the three (3) year period shall apply.

(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under the NO_x budget trading program.

(d) Copies of all documents used to complete a NO_x budget permit application and any other submission under the NO_x budget trading program or to demonstrate compliance with the requirements of the NO_x budget trading program.

This period may be extended for cause, at any time prior to the end of five (5) years, in writing by IDEM, OAQ or the U.S. EPA. Records retained at a central location within Indiana shall be available immediately at the location and submitted to IDEM, OAQ or U.S. EPA within three (3) business days following receipt of a written request. Nothing in 326 IAC 10-4-4(e) shall alter the record retention requirements for a source under 40 CFR 75. Unless otherwise provided, all records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

E.11.7 Reporting Requirements [326 IAC 10-4-4(e)]

(a) The NO_x authorized account representative of the NO_x budget source and each NO_x budget unit at the source shall submit the reports and compliance certifications required under the NO_x budget trading program, including those under 326 IAC 10-4-8, 326 IAC 10-4-12, or 326 IAC 10-4-13.

(b) Pursuant to 326 IAC 10-4-6(e), each submission shall include the following certification statement by the NO_x authorized account representative: "I am authorized to make this submission on behalf of the owners and operators of the NO_x budget sources or NO_x

budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(c) Where 326 IAC 10-4 requires a submission to IDEM, OAQ, the NO_x authorized account representative shall submit required information to:

Indiana Department of Environmental Management
Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204

(d) Where 326 IAC 10-4 requires a submission to U.S. EPA, the NO_x authorized account representative shall submit required information to:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code 6204N
Washington, DC 20460

E.11.8 Liability [326 IAC 10-4-4(f)]

The owners and operators of each NO_x budget source shall be liable as follows:

(a) Any person who knowingly violates any requirement or prohibition of the NO_x budget trading program, a NO_x budget permit, or an exemption under 326 IAC 10-4-3 shall be subject to enforcement pursuant to applicable state or federal law.

(b) Any person who knowingly makes a false material statement in any record, submission, or report under the NO_x budget trading program shall be subject to criminal enforcement pursuant to the applicable state or federal law.

(c) No permit revision shall excuse any violation of the requirements of the NO_x budget trading program that occurs prior to the date that the revision takes effect.

(d) Each NO_x budget source and each NO_x budget unit shall meet the requirements of the NO_x budget trading program.

(e) Any provision of the NO_x budget trading program that applies to a NO_x budget source, including a provision applicable to the NO_x authorized account representative of a NO_x budget source, shall also apply to the owners and operators of the source and of the NO_x budget units at the source.

(f) Any provision of the NO_x budget trading program that applies to a NO_x budget unit, including a provision applicable to the NO_x authorized account representative of a NO_x budget unit, shall also apply to the owners and operators of the unit. Except with regard to the requirements applicable to units with a common stack under 40 CFR 75 and 326 IAC 10-4-12, the owners and operators and the NO_x authorized account representative of one (1) NO_x budget unit shall not be liable for any violation by any other

NO_x budget unit of which they are not owners or operators or the NO_x authorized account representative and that is located at a source of which they are not owners or operators or the NO_x authorized account representative.

E.11.9 Effect on Other Authorities [326 IAC 10-4-4(g)]

No provision of the NO_x budget trading program, a NO_x budget permit application, a NO_x budget permit, or an exemption under 326 IAC 10-4-3 shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the NO_x authorized account representative of a NO_x budget source or NO_x budget unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the CAA.

SECTION E.12 40 CFR Part 63, Subpart Y – National Emission Standards for Marine Tank Vessel Loading Operations

E.12.1 NESHAP Subpart Y Requirements [40 CFR Part 63, Subpart Y] [326 IAC 20-17]

Pursuant to 40 CFR Part 63.560(a)(2), (a)(3), and (b)(2), the Permittee shall comply with the following applicable provisions of 40 CFR Part 63, Subpart Y, which are incorporated by reference as 326 IAC 20-17, for the Marine Dock Facility:

Subpart Y—National Emission Standards for Marine Tank Vessel Loading Operations

§63.560 Applicability and designation of affected source.

(a) *Maximum achievable control technology (MACT) standards.* (1) The provisions of this subpart pertaining to the MACT standards in §63.562(b) and (d) of this subpart are applicable to existing and new sources with emissions of 10 or 25 tons, as that term is defined in §63.561, except as specified in paragraph (d) of this section, and are applicable to new sources with emissions less than 10 and 25 tons, as that term is defined in §63.561, except as specified in paragraph (d) of this section.

(2) Existing sources with emissions less than 10 and 25 tons are not subject to the emissions standards in §63.562(b) and (d).

(3) The recordkeeping requirements of §63.567(j)(4) and the emission estimation requirements of §63.565(l) apply to existing sources with emissions less than 10 and 25 tons.

(b) *Reasonably available control technology (RACT) standards.* (1) The provisions of this subpart pertaining to RACT standards in §63.562(c) and (d) of this subpart are applicable to sources with throughput of 10 M barrels or 200 M barrels, as that term is defined in §63.561, except as specified in paragraph (d) of this section.

(2) Sources with throughput less than 10 M barrels and 200 M barrels, as that term is defined in §63.561, are not subject to the emissions standards in §63.562(c) and (d).

(d) *Exemptions from MACT and RACT standards.* (1) This subpart does not apply to emissions resulting from marine tank vessel loading operations, as that term is defined in §63.561, of commodities with vapor pressures less than 10.3 kilopascals (kPa) (1.5 pounds per square inch, absolute) (psia) at standard conditions, 20 °C and 760 millimeters Hg (mm Hg).

(2) The provisions of this subpart pertaining to the MACT standards in §63.562(b)(2), (3) and (4) and to the RACT standards in §63.562(c)(3) and (4) do not apply to marine tank vessel loading operations where emissions are reduced by using a vapor balancing system, as that term is defined in §63.561. The provisions pertaining to the vapor collection system, ship-to-shore compatibility, and vapor tightness of marine tank vessels in §63.562(b)(1) and (c)(2) do apply.

(3) The provisions of this subpart pertaining to the MACT standards in §63.562(b)(2), (3), and (4) do not apply to marine tank vessel loading operations that are contiguous with refinery operations at sources subject to and complying with subpart CC of this part, National Emissions Standards for Organic Hazardous Air Pollutants from Petroleum Refineries, except to the extent that any such provisions of this subpart are made applicable by subpart CC of this part.

(4) The provisions of this subpart pertaining to the MACT standards in §63.562(b) and (d) do not apply to benzene emissions from marine tank vessel loading operations that are subject to and complying with 40 CFR Part 61, Subpart BB, National Emissions Standards for Benzene Emissions from Benzene Transfer Operations, except that benzene emissions or other HAP emissions (i.e., nonbenzene HAP emissions) from marine tank vessel loading operations that are not subject to subpart BB are subject to the provisions of this subpart.

(5) The provisions of this subpart pertaining to the MACT standards in §63.562(b) and (d) do not apply to marine tank vessel loading operations at loading berths that only transfer liquids containing organic HAP as impurities, as that term is defined in §63.561.

(6) The provisions of this subpart do not apply to marine tank vessel loading operations at existing offshore loading terminals, as that term is defined in §63.561.

(7) The provisions of this subpart do not apply to ballasting operations, as that term is defined in §63.561.

(e) *Compliance dates—(1) MACT standards compliance dates, except the Valdez Marine Terminal (VMT) source.*

(iii) A source with emissions less than 10 and 25 tons that increases its emissions subsequent to September 20, 1999 such that it becomes a source with emissions of 10 or 25 tons shall comply with the provisions of this subpart pertaining to the MACT standards in §63.562(b) within 3 years following the exceedance of the threshold level.

(2) *RACT standards compliance dates, except the VMT source.*

(iv) A source with throughput less than 10 M barrels and 200 M barrels that increases its throughput subsequent to September 21, 1998 such that it becomes a source with throughput of 10 M barrels or 200 M barrels shall comply with the provisions of this subpart pertaining to the RACT standards in §63.562(c) within 3 years following the exceedance of the threshold levels.

(v) A source with throughput of 10 M barrels or 200 M barrels may apply for approval from the Administrator for an extension of the compliance date of up to 1 year if it can demonstrate that the additional time is necessary for installation of the control device.

§63.565 Test methods and procedures.

(l) *Emission estimation procedures.* For sources with emissions less than 10 or 25 tons and sources with emissions of 10 or 25 tons, the owner or operator shall calculate an annual estimate of HAP emissions, excluding commodities exempted by §63.560(d), from marine tank vessel loading operations. Emission estimates and emission factors shall be based on test data, or if test data is not available, shall be based on measurement or estimating techniques generally accepted in industry practice for operating conditions at the source.

§63.566 Construction and reconstruction.

(a) The owner or operator of an affected source shall fulfill all requirements for construction or reconstruction of a source in §63.5 of subpart A of this part in accordance with the provisions for applicability of subpart A to this subpart in Table 1 of §63.560 and construction or reconstruction requirements in this section.

(b)(1) *Application for approval of construction or reconstruction.* The provisions of this paragraph and §63.5(d)(1)(ii) and (iii), (2), (3), and (4) of subpart A implement section 112(i)(1) of the Act.

(2) *General application requirements.* An owner or operator who is subject to the requirements of §63.5(b)(3) of subpart A shall submit to the Administrator an application for approval of the construction of a new source, the reconstruction of a source, or the reconstruction of a source not subject to the emissions standards in §63.562 such that the source becomes an affected source. The application shall be submitted as soon as practicable before the construction or reconstruction is planned to commence. The application for approval of construction or reconstruction may be used to fulfill the initial notification requirements of §63.567(b)(3). The owner or operator may submit the application for approval well in advance of the date construction or reconstruction is planned to commence in order to ensure a timely review by the Administrator and that the planned commencement date will not be delayed.

(c) *Approval of construction or reconstruction based on prior State preconstruction review.* The owner or operator shall submit to the Administrator the request for approval of construction or reconstruction under this paragraph and §63.5(f)(1) of subpart A of this part no later than the application deadline specified in paragraph (b)(2) of this section. The owner or operator shall include in the request information sufficient for the Administrator's determination. The Administrator will evaluate the owner or operator's request in accordance with the procedures specified in §63.5(e) of subpart A of this part. The Administrator may request additional relevant information after the submittal of a request for approval of construction or reconstruction.

§63.567 Recordkeeping and reporting requirements.

(b) Notification requirements.

(1) Applicability. If a source that otherwise would not be subject to the emissions standards subsequently increases its HAP emissions calculated on a 24-month annual average basis after September 19, 1997 or increases its annual HAP emissions after September 20, 1999 or subsequently increases its gasoline or crude loading throughput calculated on a 24-month annual average basis after September 19, 1996 or increases its gasoline or crude loading annual throughput after September 21, 1998 such that the source becomes subject to the emissions standards, such source shall be subject to the notification requirements of §63.9 of subpart A of this part and the notification requirements of this paragraph.

(4) Initial notification requirements for constructed/reconstructed sources. After the effective date of these standards, whether or not an approved permit program is effective in the State in which a source subject to these standards is (or would be) located, an owner or operator subject to the notification requirements of §63.5 of subpart A of this part and §63.566 of this subpart who intends to construct a new source subject to these standards, reconstruct a source subject to these standards, or reconstruct a source such that it becomes subject to these standards, shall comply with paragraphs (b)(4)(i), (ii), (iii), and (iv) of this section.

(i) Notify the Administrator in writing of the intended construction or reconstruction. The notification shall be submitted as soon as practicable before the construction or reconstruction is planned to commence. The notification shall include all the information required for an application for approval of construction or reconstruction as specified in §63.5 of subpart A of this part. The application for approval of construction or reconstruction may be used to fulfill the requirements of this paragraph.

(ii) Submit a notification of the date when construction or reconstruction was commenced, delivered or postmarked not later than 30 days after such date, if construction was commenced after the effective date.

(iii) Submit a notification of the anticipated date of startup of the source, delivered or postmarked not more than 60 days nor less than 30 days before such date;

(iv) Submit a notification of the actual date of startup of the source, delivered or postmarked within 15 calendar days after that date.

(j) Emission estimation reporting and recordkeeping procedures.

(4) Owners or operators of marine tank vessel loading operations specified in §63.560(a)(3) shall retain records of the emissions estimates determined in §65.565(l) and records of their actual throughputs by commodity, for 5 years.

SECTION E.13 40 CFR Part 60, Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

E.13.1 General Provisions Relating to NSPS Subpart GGG [326 IAC 12] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR Part 60.1(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for each compressor, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service, except when otherwise specified in 40 CFR Part 60, Subpart GGG.

E.13.2 NSPS Requirements for Subpart GGG [326 IAC 12] [40 CFR Part 60, Subpart GGG]

Pursuant to 40 CFR 60.590, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart GGG, which are incorporated by reference as 326 IAC 12, for the emission units listed in Condition E.13.1, as specified below:

Subpart GGG—Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

§60.590 Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in petroleum refineries.

(2) A compressor is an affected facility.

(3) The group of all the equipment (defined in §60.591) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction or modification after January 4, 1983, is subject to the requirements of this subpart.

(c) Addition or replacement of equipment (defined in §60.591) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d) Facilities subject to subpart VV or subpart KKK of 40 CFR part 60 are excluded from this subpart.

§ 60.591 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the act, in subpart A of part 60, or in subpart VV of part 60, and the following terms shall have the specific meanings given them.

Alaskan North Slope means the approximately 69,000 square mile area extending from the Brooks Range to the Arctic Ocean.

Equipment means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment.

In hydrogen service means that a compressor contains a process fluid that meets the conditions specified in §60.593(b).

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.593(c).

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

Process unit means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

§60.592 Standards.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §§60.482–1 to 60.482–10 as soon as practicable, but no later than 180 days after initial startup.

(b) An owner or operator may elect to comply with the requirements of §§60.483–1 and 60.483–2.

(c) An owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of §60.484.

(d) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §60.485 except as provided in §60.593.

(e) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §§60.486 and 60.487.

§60.593 Exceptions.

(a) Each owner or operator subject to the provisions of this subpart may comply with the following exceptions to the provisions of subpart VV.

(b)(1) Compressors in hydrogen service are exempt from the requirements of §60.592 if an owner or operator demonstrates that a compressor is in hydrogen service.

(2) Each compressor is presumed not be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E260–73, 91, or 96, E168–67, 77, or 92, or E169–63, 77, or 93 (incorporated by reference as specified in §60.17) shall be used.

(3)(i) An owner or operator may use engineering judgment rather than procedures in paragraph (b)(2) of this section to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in paragraph (b)(2) shall be used to resolve the disagreement.

(ii) If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in paragraph (b)(2).

(c) Any existing reciprocating compressor that becomes an affected facility under provisions of §60.14 or §60.15 is exempt from §60.482 (a), (b), (c), (d), (e), and (h) provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of §60.482 (a), (b), (c), (d), (e), and (h).

(d) An owner or operator may use the following provision in addition to §60.485(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86–78, 82, 90, 95, or 96 (incorporated by reference as specified in §60.18).

(e) Pumps in light liquid service and valves in gas/vapor and light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the requirements of §60.482–2 and §60.482–7.

E.13.3 Deadlines Relating to the Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries [40 CFR Part 60, Subpart GGG]

The Permittee shall comply with the following requirements by the dates listed for valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, flanges and/or other connectors in VOC service:

Requirement	Rule Citations	Applicable To	Deadline
Notification of the Date Construction (or Reconstruction) is Commenced	40 CFR 60.7(a)(1)	Each affected facility	Within 30 days after commencement of construction
Notification of the Actual Date of Initial Startup	40 CFR 60.7(a)(3)	Each affected facility	Within 15 days after date of initial startup
Notification of any Physical or Operational Change	40 CFR 60.7(a)(4)	Physical or operational changes to existing affected facilities which may increase the emission rate of any pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in §60.14(e).	60 days or more prior to commencement of change or as soon as practicable
Semiannual Compliance Reports	40 CFR 60.592(e) 40 CFR 60.487(a) 40 CFR 60.487(b)	Each affected facility	Initial report shall be submitted 6 months after date of initial startup or in the next semi-annual report submitted for the existing equipment at the refinery after startup of the new equipment. Subsequent reports shall be submitted no later than 60 days after the end of each 6-month period following the first report or with the semi-annual report submitted for the existing equipment at the refinery.
Demonstrate Initial Compliance	40 CFR 60.592(a) 40 CFR 60.482-1(a)	Each affected facility	Within 180-days of initial startup

SECTION E.14 40 CFR Part 63, Subpart DD – National Emission Standards for Hazardous Air Pollutants from Off-site Waste and Recovery Operations

E.14.1 NESHAP Subpart DD Requirements [40 CFR Part 63, Subpart DD] [326IAC 20-23]

Pursuant to 40 CFR Part 63.680(d), the Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart DD, which are incorporated by reference as 326 IAC 20-23-1 for wastewater received by the wastewater treatment facility.

Subpart DD—National Emission Standards for Hazardous Air Pollutants from Off-Site Waste and Recovery Operations

§63.680 Applicability and designation of affected sources.

(a) The provisions of this subpart apply to the owner and operator of a plant site for which both of the conditions specified in paragraphs (a)(1) and (a)(2) of this section are applicable. If either one of these conditions does not apply to the plant site, then the owner and operator of the plant site are not subject to the provisions of this subpart.

(1) The plant site is a major source of hazardous air pollutant (HAP) emissions as defined in 40 CFR 63.2.

(2) At the plant site is located one or more of operations that receives off-site materials as specified in paragraph (b) of this section and the operations is one of the following waste management operations or recovery operations as specified in paragraphs (a)(2)(i) through (a)(2)(vi) of this section.

(i) A waste management operation that receives off-site material and the operation is regulated as a hazardous waste treatment, storage, and disposal facility (TSDF) under either 40 CFR part 264 or part 265.

(b) For the purpose of implementing this subpart, an off-site material is a material that meets all of the criteria specified in paragraph (b)(1) of this section but is not one of the materials specified in paragraph (b)(2) of this section.

(1) An off-site material is a material that meets all of the criteria specified in paragraphs (b)(1)(i) through (b)(1)(iii) of this section. If any one of these criteria do not apply to the material, then the material is not an off-site material subject to this subpart.

(i) The material is a waste, used oil, or used solvent as defined in §63.681 of this subpart;

(ii) The waste, used oil, or used solvent is not produced or generated within the plant site, but the material is delivered, transferred, or otherwise moved to the plant site from a location outside the boundaries of the plant site; and

(iii) The waste, used oil, or used solvent contains one or more of the hazardous air pollutants (HAP) listed in Table 1 of this subpart based on the composition of the material at the point-of-delivery, as defined in §63.681 of this subpart.

(2) For the purpose of implementing this subpart, the following materials are not off-site materials:

(i) Household waste as defined in 40 CFR 258.2.

(ii) Radioactive mixed waste managed in accordance with all applicable regulations under Atomic Energy Act and Nuclear Waste Policy Act authorities.

(iii) Waste that is generated as a result of implementing remedial activities required under the Resource Conservation and Recovery Act (RCRA) corrective action authorities (RCRA sections 3004(u), 3004(v), or 3008(h)), Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) authorities, or similar Federal or State authorities.

(iv) Waste containing HAP that is generated by residential households (e.g., old paint, home garden pesticides) and subsequently is collected as a community service by government agencies, businesses, or other organizations for the purpose of promoting the proper disposal of this waste.

(v) Waste that is transferred from a chemical manufacturing plant or other facility for which both of the following conditions apply to the waste:

(A) The management of the waste at the facility is required either under part 63 subpart F—National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry or under another subpart in 40 CFR part 63 to meet the air emission control standards for process wastewater specified in 40 CFR 63.132 through 63.147; and

(B) The owner or operator of the facility from which the waste is transferred has complied with the provisions of 40 CFR 63.132(g)(1)(ii) and (g)(2).

(vi) Waste that is transferred from a chemical manufacturing plant, petroleum refinery, or coke by-product recovery plant which is subject to 40 CFR part 61, subpart FF—National Emission Standards for Benzene Waste Operations, and for which both of the following conditions apply to the waste:

(A) The waste is generated at a facility that is not exempted under the provisions of 40 CFR 61.342(a) from meeting the air emission control standards of 40 CFR part 61, subpart FF; and

(B) The owner or operator of the facility from which the waste is transferred has complied with the provisions of 40 CFR 61.342(f)(2).

(vii) Ship ballast water pumped from a ship to an onshore wastewater treatment facility.

(viii) Hazardous waste that is stored for 10 days or less at a transfer facility in compliance with the provisions of 40 CFR 263.12.

(c) *Affected sources.* (1) *Off-site material management units.* For each operation specified in paragraphs (a)(2)(i) through (a)(2)(vi) of this section that is located at the plant site, the affected source is the entire group of off-site material management units associated with the operation. An off-site material management unit is a tank, container, surface impoundment, oil-water separator, organic-water separator, or transfer system used to manage off-site material. For the purpose of implementing the standards under this subpart, a unit that meets the definition of a tank or container but also is equipped with a vent that serves as a process vent for any of the processes listed in paragraphs (c)(2)(i) through (c)(2)(vi) of this section is not an off-site material management unit but instead is a process vent and is to be included in the appropriate affected source group under paragraph (c)(2) of this section. Examples of such a unit may include, but are not limited to, a distillate receiver vessel, a primary condenser, a bottoms receiver vessel, a surge control tank, a separator tank, and a hot well.

(d) *Facility-wide exemption*. The owner or operator of affected sources subject to this subpart is exempted from the requirements of §§63.682 through 63.699 of this subpart in situations when the total annual quantity of the HAP that is contained in the off-site material received at the plant site is less than 1 megagram per year. For a plant site to be exempted under the provisions of this paragraph (d), the owner or operator must meet the requirements in paragraphs (d)(1) through (d)(3) of this section.

(1) The owner or operator must prepare an initial determination of the total annual HAP quantity in the off-site material received at the plant site. This determination is based on the total quantity of the HAP listed in Table 1 of this subpart as determined at the point-of-delivery for each off-site material stream.

(2) The owner or operator must prepare a new determination whenever the extent of changes to the quantity or composition of the off-site material received at the plant site could cause the total annual HAP quantity in the off-site material received at the plant site to exceed the limit of 1 megagram per year.

(3) The owner or operator must maintain documentation to support the owner's or operator's determination of the total annual HAP quantity in the off-site material received at the plant site. This documentation must include the basis and data used for determining the HAP content of the off-site material.

(e) *Compliance dates.* (1) *Existing sources.* The owner or operator of an affected source that commenced construction or reconstruction before October 13, 1994, must achieve compliance with the provisions of this subpart on or before the date specified in paragraph (e)(1)(i) or (e)(1)(ii) of this section as applicable to the affected source.

(i) For an affected source that commenced construction or reconstruction before October 13, 1994 and receives off-site material for the first time before February 1, 2000, the owner or operator of this affected source must achieve compliance with the provisions of the subpart on or before February 1, 2000 unless an extension has been granted by the Administrator as provided in 40 CFR 63.6(i).

(ii) For an affected source that commenced construction or reconstruction before October 13, 1994, but receives off-site material for the first time on or after February 1, 2000, the owner or operator of the affected source must achieve compliance with the provisions of this subpart upon the first date that the affected source begins to manage off-site material.

Table 1 to Subpart DD of Part 63—List of Hazardous Air Pollutants (HAP) for Subpart DD

CAS No. a	Chemical name	fm 305
75-07-0	Acetaldehyde	1.000
75-05-8	Acetonitrile	0.989
98-86-2	Acetophenone	0.314
107-02-8	Acrolein	1.000
107-13-1	Acrylonitrile	0.999
107-05-1	Allyl chloride	1.000
71-43-2	Benzene (includes benzene in gasoline)	1.000
98-07-7	Benzotrichloride (isomers and mixture)	0.958
100-44-7	Benzyl chloride	1.000
92-52-4	Biphenyl	0.864
542-88-1	Bis(chloromethyl)ether b	0.999
75-25-2	Bromoform	0.998
106-99-0	1,3-Butadiene	1.000
75-15-0	Carbon disulfide	1.000
56-23-5	Carbon tetrachloride	1.000
43-58-1	Carbonyl sulfide	1.000
133-90-4	Chloramben	0.633
108-90-7	Chlorobenzene	1.000
67-66-3	Chloroform	1.000
107-30-2	Chloromethyl methyl ether b	1.000
126-99-8	Chloroprene	1.000
98-82-8	Cumene	1.000
94-75-7	2,4-D, salts and esters	0.167
334-88-3	Diazomethane c	0.999
132-64-9	Dibenzofurans	0.967
96-12-8	1,2-Dibromo-3-chloropropane	1.000
106-46-7	1,4-Dichlorobenzene(p)	1.000
107-06-2	Dichloroethane (Ethylene dichloride)	1.000
111-44-4	Dichloroethyl ether (Bis(2-chloroethyl ether)	0.757
542-75-6	1,3-Dichloropropene	1.000
79-44-7	Dimethyl carbamoyl chloridec	0.150
64-67-5	Diethyl sulfate	0.003
77-78-1	Dimethyl sulfate	0.086

CAS No. a	Chemical name	fm 305
121-69-7	N,N-Dimethylaniline	0.001
51-28-5	2,4-Dinitrophenol	0.008
121-14-2	2,4-Dinitrotoluene	0.085
123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)	0.869
106-89-8	Epichlorohydrin (1-Chloro-2,3-epoxypropane)	0.939
106-88-7	1,2-Epoxybutane	1.000
140-88-5	Ethyl acrylate	1.000
100-41-4	Ethyl benzene	1.000
75-00-3	Ethyl chloride (Chloroethane)	1.000
106-93-4	Ethylene dibromide (Dibromoethane)	0.999
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	1.000
151-56-4	Ethylene imine (Aziridine)	0.867
75-21-8	Ethylene oxide	1.000
75-34-3	Ethylidene dichloride (1,1-Dichloroethane)	1.000
	Glycol ethers d that have a Henry's Law constant value equal to or greater than 0.1 Y/X (1.8x10-6 atm/gm-mole/m\3\) at 25°C	(e)
118-74-1	Hexachlorobenzene	0.970
87-68-3	Hexachlorobutadiene	0.880
67-72-1	Hexachloroethane	0.499
110-54-3	Hexane	1.000
78-59-1	Isophorone	0.506
58-89-9	Lindane (all isomers)	1.000
67-56-1	Methanol	0.855
74-83-9	Methyl bromide (Bromomethane)	1.000
74-87-3	Methyl chloride (Choromethane)	1.000
71-55-6	Methyl chloroform (1,1,1-Trichloroethane)	1.000
78-93-3	Methyl ethyl ketone (2-Butanone)	0.990
74-88-4	Methyl iodide (Iodomethane)	1.000
108-10-1	Methyl isobutyl ketone (Hexone)	0.980
624-83-9	Methyl isocyanate	1.000
80-62-6	Methyl methacrylate	0.916
1634-04-4	Methyl tert butyl ether	1.000
75-09-2	Methylene chloride (Dichloromethane)	1.000
91-20-3	Naphthalene	0.994
98-95-3	Nitrobenzene	0.394
79-46-9	2-Nitropropane	0.989
82-68-8	Pentachloronitrobenzene (Quintobenzene)	0.839
87-86-5	Pentachlorophenol	0.090
75-44-5	Phosgene c	1.000
123-38-6	Propionaldehyde	0.999
78-87-5	Propylene dichloride (1,2-Dichloropropane)	1.000
75-56-9	Propylene oxide	1.000
75-55-8	1,2-Propylenimine (2-Methyl aziridine)	0.945
100-42-5	Styrene	1.000
96-09-3	Styrene oxide	0.830
79-34-5	1,1,2,2-Tetrachloroethane	0.999
127-18-4	Tetrachloroethylene (Perchloroethylene)	1.000
108-88-3	Toluene	1.000
95-53-4	o-Toluidine	0.152
120-82-1	1,2,4-Trichlorobenzene	1.000
71-55-6	1,1,1-Trichloroethane (Methyl chloroform)	1.000
79-00-5	1,1,2-Trichloroethane (Vinyl trichloride)	1.000

CAS No. a	Chemical name	fm 305
79-01-6	Trichloroethylene	1.000
95-95-4	2,4,5-Trichlorophenol	0.108
88-06-2	2,4,6-Trichlorophenol	0.132
121-44-8	Triethylamine	1.000
540-84-1	2,2,4-Trimethylpentane	1.000
108-05-4	Vinyl acetate	1.000
593-60-2	Vinyl bromide	1.000
75-01-4	Vinyl chloride	1.000
75-35-4	Vinylidene chloride (1,1-Dichloroethylene)	1.000
1330-20-7	Xylenes (isomers and mixture)	1.000
95-47-6	o-Xylenes	1.000
108-38-3	m-Xylenes	1.000
106-42-3	p-Xylenes	1.000

Notes:
fm 305 = Method 305 fraction measure factor.

a. CAS numbers refer to the Chemical Abstracts Services registry number assigned to specific compounds, isomers, or mixtures of compounds.
b. Denotes a HAP that hydrolyzes quickly in water, but the hydrolysis products are also HAP chemicals.
c. Denotes a HAP that may react violently with water, exercise caustic is an expected analyte.
d. Denotes a HAP that hydrolyzes slowly in water.
e. The fm 305 factors for some of the more common glycol ethers can be obtained by contacting the Waste and Chemical Processes Group, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

SECTION E.15 40 CFR Part 60, Subpart XX – Standards of Performance for Bulk Gasoline Terminals

E.15.1 General Provisions Relating to NSPS Subpart XX [326 IAC 12-1] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR Part 60.1(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the Marketing Terminal, except when otherwise specified in 40 CFR Part 60, Subpart XX.

E.15.2 NSPS Requirements for Subpart XX [40 CFR Part 60, Subpart XX] [326 IAC 12]

Pursuant to 40 CFR 60.500, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart XX, which are incorporated by reference as 326 IAC 12, for the bulk truck loading facilities located at the Marketing Terminal as specified below:

Subpart XX—Standards of Performance for Bulk Gasoline Terminals

§60.500 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is the total of all the loading racks at a bulk gasoline terminal which deliver liquid product into gasoline tank trucks.

(b) Each facility under paragraph (a) of this section, the construction or modification of which is commenced after December 17, 1980, is subject to the provisions of this subpart.

(c) For purposes of this subpart, any replacement of components of an existing facility, described in paragraph (a) of this section, commenced before August 18, 1983 in order to comply with any emission standard adopted by a State or political subdivision thereof will not be considered a reconstruction under the provisions of 40 CFR 60.15.

Note: The intent of these standards is to minimize the emissions of VOC through the application of best demonstrated technologies (BDT). The numerical emission limits in this standard are expressed in terms of total organic compounds. This emission limit reflects the performance of BDT.

§60.502 Standard for Volatile Organic Compound (VOC) emissions from bulk gasoline terminals.

On and after the date on which §60.8(a) requires a performance test to be completed, the owner or operator of each bulk gasoline terminal containing an affected facility shall comply with the requirements of this section.

(a) Each affected facility shall be equipped with a vapor collection system designed to collect the total organic compounds vapors displaced from tank trucks during product loading.

(b) The emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline tank trucks are not to exceed 35 milligrams of total organic compounds per liter of gasoline loaded, except as noted in paragraph (c) of this section.

(c) For each affected facility equipped with an existing vapor processing system, the emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline tank trucks are not to exceed 80 milligrams of total organic compounds per liter of gasoline loaded.

(d) Each vapor collection system shall be designed to prevent any total organic compounds vapors collected at one loading rack from passing to another loading rack.

(e) Loadings of liquid product into gasoline tank trucks shall be limited to vapor-tight gasoline tank trucks using the following procedures:

(1) The owner or operator shall obtain the vapor tightness documentation described in §60.505(b) for each gasoline tank truck which is to be loaded at the affected facility.

(2) The owner or operator shall require the tank identification number to be recorded as each gasoline tank truck is loaded at the affected facility.

(3)(i) The owner or operator shall cross-check each tank identification number obtained in paragraph (e)(2) of this section with the file of tank vapor tightness documentation within 2 weeks after the corresponding tank is loaded, unless either of the following conditions is maintained:

(A) If less than an average of one gasoline tank truck per month over the last 26 weeks is loaded without vapor tightness documentation then the documentation cross-check shall be performed each quarter; or

(B) If less than an average of one gasoline tank truck per month over the last 52 weeks is loaded without vapor tightness documentation then the documentation cross-check shall be performed semiannually.

(ii) If either the quarterly or semiannual cross-check provided in paragraphs (e)(3)(i) (A) through (B) of this section reveals that these conditions were not maintained, the source must return to biweekly monitoring until such time as these conditions are again met.

(4) The terminal owner or operator shall notify the owner or operator of each non-vapor-tight gasoline tank truck loaded at the affected facility within 1 week of the documentation cross-check in paragraph (e)(3) of this section.

(5) The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline tank truck will not be reloaded at the affected facility until vapor tightness documentation for that tank is obtained.

(6) Alternate procedures to those described in paragraphs (e)(1) through (5) of this section for limiting gasoline tank truck loadings may be used upon application to, and approval by, the Administrator.

(f) The owner or operator shall act to assure that loadings of gasoline tank trucks at the affected facility are made only into tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system.

(g) The owner or operator shall act to assure that the terminal's and the tank truck's vapor collection systems are connected during each loading of a gasoline tank truck at the affected facility. Examples of actions to accomplish this include training drivers in the hookup procedures and posting visible reminder signs at the affected loading racks.

(h) The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the delivery tank from exceeding 4,500 pascals (450 mm of water) during product loading. This level is not to be exceeded when measured by the procedures specified in §60.503(d).

(i) No pressure-vacuum vent in the bulk gasoline terminal's vapor collection system shall begin to open at a system pressure less than 4,500 pascals (450 mm of water).

(j) Each calendar month, the vapor collection system, the vapor processing system, and each loading rack handling gasoline shall be inspected during the loading of gasoline tank trucks for total organic compounds liquid or vapor leaks. For purposes of this paragraph, detection methods incorporating sight, sound, or smell are acceptable. Each detection of a leak shall be recorded and the source of the leak repaired within 15 calendar days after it is detected.

§60.503 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as

specified in this section, except as provided in §60.8(b). The three-run requirement of §60.8(f) does not apply to this subpart.

(b) Immediately before the performance test required to determine compliance with §60.502 (b), (c), and (h), the owner or operator shall use Method 21 to monitor for leakage of vapor all potential sources in the terminal's vapor collection system equipment while a gasoline tank truck is being loaded. The owner or operator shall repair all leaks with readings of 10,000 ppm (as methane) or greater before conducting the performance test.

(c) The owner or operator shall determine compliance with the standards in §60.502 (b) and (c) as follows:

(1) The performance test shall be 6 hours long during which at least 300,000 liters of gasoline is loaded. If this is not possible, the test may be continued the same day until 300,000 liters of gasoline is loaded or the test may be resumed the next day with another complete 6-hour period. In the latter case, the 300,000-liter criterion need not be met. However, as much as possible, testing should be conducted during the 6-hour period in which the highest throughput normally occurs.

(2) If the vapor processing system is intermittent in operation, the performance test shall begin at a reference vapor holder level and shall end at the same reference point. The test shall include at least two startups and shutdowns of the vapor processor. If this does not occur under automatically controlled operations, the system shall be manually controlled.

(3) The emission rate (E) of total organic compounds shall be computed using the following equation:

$$E = K\sum_{i=1}^{n}\left(V_{esi}C_{ei}\right)/\left(L\,10^{6}\right)$$

where:

E=emission rate of total organic compounds, mg/liter of gasoline loaded.

V_{esi}=volume of air-vapor mixture exhausted at each interval “i”, scm.

C_{ei}=concentration of total organic compounds at each interval “i”, ppm.

L=total volume of gasoline loaded, liters.

n=number of testing intervals.

i=emission testing interval of 5 minutes.

K=density of calibration gas, 1.83×10^{6} for propane and 2.41×10^{6} for butane, mg/scm.

(4) The performance test shall be conducted in intervals of 5 minutes. For each interval “i”, readings from each measurement shall be recorded, and the volume exhausted (V_{esi}) and the corresponding average total organic compounds concentration (C_{ei}) shall be determined. The sampling system response time shall be considered in determining the average total organic compounds concentration corresponding to the volume exhausted.

(5) The following methods shall be used to determine the volume (V_{esi}) air-vapor mixture exhausted at each interval:

(i) Method 2B shall be used for combustion vapor processing systems.

(ii) Method 2A shall be used for all other vapor processing systems.

(6) Method 25A or 25B shall be used for determining the total organic compounds concentration (C_{ei}) at each interval. The calibration gas shall be either propane or butane. The owner or operator may exclude the methane and ethane content in the exhaust vent by any method (e.g., Method 18) approved by the Administrator.

(7) To determine the volume (L) of gasoline dispensed during the performance test period at all loading racks whose vapor emissions are controlled by the processing system being tested, terminal records or readings from gasoline dispensing meters at each loading rack shall be used.

(d) The owner or operator shall determine compliance with the standard in §60.502(h) as follows:

(1) A pressure measurement device (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to 500 mm of water gauge pressure with ±2.5 mm of water precision, shall be calibrated and installed on the terminal's vapor collection system at a pressure tap located as close as possible to the connection with the gasoline tank truck.

(2) During the performance test, the pressure shall be recorded every 5 minutes while a gasoline truck is being loaded; the highest instantaneous pressure that occurs during each loading shall also be recorded. Every loading position must be tested at least once during the performance test.

§60.505 Reporting and recordkeeping.

(a) The tank truck vapor tightness documentation required under §60.502(e)(1) shall be kept on file at the terminal in a permanent form available for inspection.

(b) The documentation file for each gasoline tank truck shall be updated at least once per year to reflect current test results as determined by Method 27. This documentation shall include, as a minimum, the following information:

(1) Test title: Gasoline Delivery Tank Pressure Test—EPA Reference Method 27.

(2) Tank owner and address.

(3) Tank identification number.

(4) Testing location.

(5) Date of test.

(6) Tester name and signature.

(7) Witnessing inspector, if any: Name, signature, and affiliation.

(8) Test results: Actual pressure change in 5 minutes, mm of water (average for 2 runs).

(c) A record of each monthly leak inspection required under §60.502(j) shall be kept on file at the terminal for at least 2 years. Inspection records shall include, as a minimum, the following information:

(1) Date of inspection.

(2) Findings (may indicate no leaks discovered; or location, nature, and severity of each leak).

(3) Leak determination method.

(4) Corrective action (date each leak repaired; reasons for any repair interval in excess of 15 days).

(5) Inspector name and signature.

(d) The terminal owner or operator shall keep documentation of all notifications required under §60.502(e)(4) on file at the terminal for at least 2 years.

(e) As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in paragraphs (a), (c), and (d) of this section, an owner or operator may comply with the requirements in either paragraph (e)(1) or (2) of this section.

(1) An electronic copy of each record is instantly available at the terminal.

(i) The copy of each record in paragraph (e)(1) of this section is an exact duplicate image of the original paper record with certifying signatures.

(ii) The permitting authority is notified in writing that each terminal using this alternative is in compliance with paragraph (e)(1) of this section.

(2) For facilities that utilize a terminal automation system to prevent gasoline cargo tanks that do not have valid cargo tank vapor tightness documentation from loading (*e.g.,* via a card lock-out system), a copy of the documentation is made available (*e.g.,* via facsimile) for inspection by permitting authority representatives during the course of a site visit, or within a mutually agreeable time frame.

(i) The copy of each record in paragraph (e)(2) of this section is an exact duplicate image of the original paper record with certifying signatures.

(ii) The permitting authority is notified in writing that each terminal using this alternative is in compliance with paragraph (e)(2) of this section.

(f) The owner or operator of an affected facility shall keep records of all replacements or additions of components performed on an existing vapor processing system for at least 3 years.

§60.506 Reconstruction.

For purposes of this subpart:

(a) The cost of the following frequently replaced components of the affected facility shall not be considered in calculating either the “fixed capital cost of the new components” or the “fixed capital costs that would be required to construct a comparable entirely new facility” under §60.15: pump seals, loading arm gaskets and swivels, coupler gaskets, overfill sensor couplers and cables, flexible vapor hoses, and grounding cables and connectors.

(b) Under §60.15, the “fixed capital cost of the new components” includes the fixed capital cost of all depreciable components (except components specified in §60.506(a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following December 17, 1980. For purposes of this paragraph, “commenced” means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

SECTION E.16 40 CFR Part 63, Subpart R – National Emission Standards for Hazardous Air Pollutants for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

E.16.1 NESHAP Subpart R Requirements [40 CFR Part 63, Subpart R]

Pursuant to 40 CFR Part 63, Subpart CC, the Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart R:

Subpart R—National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

§63.420 Applicability.

(i) A bulk gasoline terminal or pipeline breakout station with a Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery complying with subpart CC, §§63.646, 63.648, 63.649, and 63.650 is not subject to subpart R standards, except as specified in subpart CC, §63.650.

§63.422 Standards: Loading racks.

(a) Each owner or operator of loading racks at a bulk gasoline terminal subject to the provisions of this subpart shall comply with the requirements in §60.502 of this chapter except for paragraphs (b), (c), and (j) of that section. For purposes of this section, the term “affected facility” used in §60.502 of this chapter means the loading racks that load gasoline cargo tanks at the bulk gasoline terminals subject to the provisions of this subpart.

(b) Emissions to the atmosphere from the vapor collection and processing systems due to the loading of gasoline cargo tanks shall not exceed 10 milligrams of total organic compounds per liter of gasoline loaded.

(c) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall comply with §60.502(e) of this chapter as follows:

(1) For the purposes of this section, the term “tank truck” as used in §60.502(e) of this chapter means “cargo tank.”

(2) Section 60.502(e)(5) of this chapter is changed to read: The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline cargo tank will not be reloaded at the facility until vapor tightness documentation for that gasoline cargo tank is obtained which documents that:

(i) The tank truck or railcar gasoline cargo tank meets the test requirements in §63.425(e), or the railcar gasoline cargo tank meets applicable test requirements in §63.425(i);

(ii) For each gasoline cargo tank failing the test in §63.425 (f) or (g) at the facility, the cargo tank either:

(A) Before repair work is performed on the cargo tank, meets the test requirements in §63.425 (g) or (h), or

(B) After repair work is performed on the cargo tank before or during the tests in §63.425 (g) or (h), subsequently passes the annual certification test described in §63.425(e).

§63.425 Test methods and procedures.

(a) Each owner or operator subject to the emission standard in §63.422(b) or 40 CFR 60.112b(a)(3)(ii) shall comply with the requirements in paragraphs (a)(1) and (2) of this section.

(1) Conduct a performance test on the vapor processing and collection systems according to either paragraph (a)(1)(i) or (ii) of this section.

(i) Use the test methods and procedures in 40 CFR 60.503 of this chapter, except a reading of 500 ppm shall be used to determine the level of leaks to be repaired under 40 CFR 60.503(b), or

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in §63.7(f).

(2) The performance test requirements of 40 CFR 60.503(c) do not apply to flares defined in §63.421 and meeting the flare requirements in §63.11(b). The owner or operator shall demonstrate that the flare and associated vapor collection system is in compliance with the requirements in §63.11(b) and 40 CFR 60.503(a), (b), and (d), respectively.

(b) For each performance test conducted under paragraph (a) of this section, the owner or operator shall determine a monitored operating parameter value for the vapor processing system using the following procedure:

(1) During the performance test, continuously record the operating parameter under §63.427(a);

(2) Determine an operating parameter value based on the parameter data monitored during the performance test, supplemented by engineering assessments and the manufacturer's recommendations; and

(3) Provide for the Administrator's approval the rationale for the selected operating parameter value, and monitoring frequency and averaging time, including data and calculations used to develop the value and a description of why the value, monitoring frequency, and averaging time demonstrate continuous compliance with the emission standard in §63.422(b) or §60.112b(a)(3)(ii) of this chapter.

(c) For performance tests performed after the initial test, the owner or operator shall document the reasons for any change in the operating parameter value since the previous performance test.

(e) *Annual certification test.* The annual certification test for gasoline cargo tanks shall consist of the following test methods and procedures:

(1) Method 27, appendix A, 40 CFR part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure (P_i) for the pressure test shall be 460 mm H_2 O (18 in. H_2 O), gauge. The initial vacuum (V_i) for the vacuum test shall be 150 mm H_2 O (6 in. H_2 O), gauge. The maximum allowable pressure and vacuum changes (Δ p, Δ v) are as shown in the second column of Table 2 of this paragraph.

Table 2_Allowable Cargo Tank Test Pressure or Vacuum Change

Cargo tank or compartment capacity, liters (gal)	Annual certification allowable pressure or vacuum change (Δ p, Δ v) in 5 minutes, mm H2O (in. H2 O)	Allowable pressure change (Δ p) in 5 minutes at any time, mm H2O (in. H2O)
9,464 or more (2,500 or more)	25 (1.0)	64 (2.5)
9,463 to 5,678 (2,499 to 1,500)	38 (1.5)	76 (3.0)
5,679 to 3,785 (1,499 to 1,000)	51 (2.0)	89 (3.5)
3,782 or less (999 or less)	64 (2.5)	102 (4.0)

(2) Pressure test of the cargo tank's internal vapor valve as follows:

(i) After completing the tests under paragraph (e)(1) of this section, use the procedures in Method 27 to repressurize the tank to 460 mm H_2O (18 in. H_2O), gauge. Close the tank's internal vapor valve(s), thereby isolating the vapor return line and manifold from the tank.

(ii) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 130 mm H_2O (5 in. H_2O).

(f) *Leak detection test.* The leak detection test shall be performed using Method 21, appendix A, 40 CFR part 60, except omit section 4.3.2 of Method 21. A vapor-tight gasoline cargo tank shall have no leaks at any time when tested according to the procedures in this paragraph.

(1) The leak definition shall be 21,000 ppm as propane. Use propane to calibrate the instrument, setting the span at the leak definition. The response time to 90 percent of the final stable reading shall be less than 8 seconds for the detector with the sampling line and probe attached.

(2) In addition to the procedures in Method 21, include the following procedures:

(i) Perform the test on each compartment during loading of that compartment or while the compartment is still under pressure.

(ii) To eliminate a positive instrument drift, the dwell time for each leak detection shall not exceed two times the instrument response time. Purge the instrument with ambient air between each leak detection. The duration of the purge shall be in excess of two instrument response times.

(iii) Attempt to block the wind from the area being monitored. Record the highest detector reading and location for each leak.

(g) *Nitrogen pressure decay field test.* For those cargo tanks with manifolded product lines, this test procedure shall be conducted on each compartment.

(1) Record the cargo tank capacity. Upon completion of the loading operation, record the total volume loaded. Seal the cargo tank vapor collection system at the vapor coupler. The sealing apparatus shall have a pressure tap. Open the internal vapor valve(s) of the cargo tank and record the initial headspace pressure. Reduce or increase, as necessary, the initial headspace pressure to 460 mm H_2O (18.0 in. H_2O), gauge by releasing pressure or by adding commercial grade nitrogen gas from a high pressure cylinder capable of maintaining a pressure of 2,000 psig.

(i) The cylinder shall be equipped with a compatible two-stage regulator with a relief valve and a flow control metering valve. The flow rate of the nitrogen shall be no less than 2 cfm. The maximum allowable time to pressurize cargo tanks with headspace volumes of 1,000 gallons or less to the appropriate pressure is 4 minutes. For cargo tanks with a headspace of greater than 1,000 gallons, use as a maximum allowable time to pressurize 4 minutes or the result from the equation below, whichever is greater.

$T = V_h \times 0.004$

where:

T = maximum allowable time to pressurize the cargo tank, min;

V_h = cargo tank headspace volume during testing, gal.

(2) It is recommended that after the cargo tank headspace pressure reaches approximately 460 mm H_2O (18 in. H_20), gauge, a fine adjust valve be used to adjust the headspace pressure to 460 mm H_2O (18.0 in. H_2O), gauge for the next 30 ±5 seconds.

(3) Reseal the cargo tank vapor collection system and record the headspace pressure after 1 minute. The measured headspace pressure after 1 minute shall be greater than the minimum allowable final headspace pressure (P_F) as calculated from the following equation:

$$P_F = 18\left(\frac{(18-N)}{18}\right)^{\left(\frac{V_s}{5(V_h)}\right)}$$

where:

(P_F) = minimum allowable final headspace pressure, in. H_2O, gauge;

V_s = total cargo tank shell capacity, gal;

V_h = cargo tank headspace volume after loading, gal;

18.0 = initial pressure at start of test, in. H_2O, gauge;

N = 5-minute continuous performance standard at any time from the third column of Table 2 of §63.425(e)(i), inches H_2O.

(4) Conduct the internal vapor valve portion of this test by repressurizing the cargo tank headspace with nitrogen to 460 mm H_2O (18 in. H_2O), gauge. Close the internal vapor valve(s), wait for 30 ±5 seconds, then relieve the pressure downstream of the vapor valve in the vapor collection system to atmospheric pressure. Wait 15 seconds, then reseal the vapor collection system. Measure and record the pressure every minute for 5 minutes. Within 5 seconds of the pressure measurement at the end of 5 minutes, open the vapor valve and record the headspace pressure as the “final pressure.”

(5) If the decrease in pressure in the vapor collection system is less than at least one of the interval pressure change values in Table 3 of this paragraph, or if the final pressure is equal to or greater than 20 percent of the 1-minute final headspace pressure determined in the test in paragraph (g)(3) of this section, then the cargo tank is considered to be a vapor-tight gasoline cargo tank.

Table 3_Pressure Change for Internal Vapor Valve Test

Time interval	Interval pressure change, mm H2O (in. H2O)
After 1 minute	28 (1.1)
After 2 minutes	56 (2.2)
After 3 minutes	84 (3.3)
After 4 minutes	112 (4.4)
After 5 minutes	140 (5.5)

(h) *Continuous performance pressure decay test.* The continuous performance pressure decay test shall be performed using Method 27, appendix A, 40 CFR part 60. Conduct only the positive pressure test using a time period (t) of 5 minutes. The initial pressure (P_i) shall be 460 mm H_2O (18 in. H_2O), gauge. The maximum allowable 5-minute pressure change (Δ p) which shall be met at any time is shown in the third column of Table 2 of §63.425(e)(1).

§63.427 Continuous monitoring.

(a) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall install, calibrate, certify, operate, and maintain, according to the manufacturer's specifications, a continuous monitoring system (CMS) as specified in paragraph (a)(1), (a)(2), (a)(3), or (a)(4) of this section, except as allowed in paragraph (a)(5) of this section.

(3) Where a thermal oxidation system other than a flare is used, a CPMS capable of measuring temperature must be installed in the firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs.

(b) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall operate the vapor processing system in a manner not to exceed the operating parameter value for the parameter described in paragraphs (a)(1) and (a)(2) of this section, or to go below the operating parameter value for the parameter described in paragraph (a)(3) of this section, and established using the procedures in §63.425(b). In cases where an alternative parameter pursuant to paragraph (a)(5) of this section is approved, each owner or operator shall operate the vapor processing system in a manner not to exceed or not to go below, as appropriate, the alternative operating parameter value. Operation of the vapor processing system in a manner exceeding or going below the operating parameter value, as specified above, shall constitute a violation of the emission standard in §63.422(b).

§63.428 Reporting and recordkeeping.

(b) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall keep records of the test results for each gasoline cargo tank loading at the facility as follows:

(1) Annual certification testing performed under §63.425(e) and railcar bubble leak testing performed under §63.425(k); and

(2) Continuous performance testing performed at any time at that facility under §63.425 (f), (g), and (h).

(3) The documentation file shall be kept up-to-date for each gasoline cargo tank loading at the facility. The documentation for each test shall include, as a minimum, the following information:

(i) Name of test: Annual Certification Test—Method 27 (§63.425(e)(1)); Annual Certification Test—Internal Vapor Valve (§63.425(e)(2)); Leak Detection Test (§63.425(f)); Nitrogen Pressure Decay Field Test (§63.425(g)); Continuous Performance Pressure Decay Test (§63.425(h)); or Railcar Bubble Leak Test Procedure (§63.425(i)).

(ii) Cargo tank owner's name and address.

(iii) Cargo tank identification number.

(iv) Test location and date.

(v) Tester name and signature.

(vi) Witnessing inspector, if any: Name, signature, and affiliation.

(vii) Vapor tightness repair: Nature of repair work and when performed in relation to vapor tightness testing.

(viii) Test results: test pressure; pressure or vacuum change, mm of water; time period of test; number of leaks found with instrument; and leak definition.

(c) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall:

(1) Keep an up-to-date, readily accessible record of the continuous monitoring data required under §63.427(a). This record shall indicate the time intervals during which loadings of gasoline cargo tanks have occurred or, alternatively, shall record the operating parameter data only during such loadings. The date and time of day shall also be indicated at reasonable intervals on this record.

(2) Record and report simultaneously with the notification of compliance status required under §63.9(h):

(i) All data and calculations, engineering assessments, and manufacturer's recommendations used in determining the operating parameter value under §63.425(b); and

(ii) The following information when using a flare under provisions of §63.11(b) to comply with §63.422(b):

(A) Flare design (i.e., steam-assisted, air-assisted, or non-assisted); and

(B) All visible emissions readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required under §63.425(a).

(g) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall include in a semiannual report to the Administrator the following information, as applicable:

(1) Each loading of a gasoline cargo tank for which vapor tightness documentation had not been previously obtained by the facility;

(2) Periodic reports required under paragraph (d) of this section; and

(3) The number of equipment leaks not repaired within 5 days after detection.

(h) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall submit an excess emissions report to the Administrator in accordance with §63.10(e)(3), whether or not a CMS is installed at the facility. The following occurrences are excess emissions events under this subpart, and the following information shall be included in the excess emissions report, as applicable:

(1) Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under §63.425(b). The report shall include the monitoring data for the days on which exceedances or failures to maintain have occurred, and a description and timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CMS.

(2) Each instance of a nonvapor-tight gasoline cargo tank loading at the facility in which the owner or operator failed to take steps to assure that such cargo tank would not be reloaded at the facility before vapor tightness documentation for that cargo tank was obtained.

(3) Each reloading of a nonvapor-tight gasoline cargo tank at the facility before vapor tightness documentation for that cargo tank is obtained by the facility in accordance with §63.422(c)(2).

(4) At any time following the notification required under paragraph (i)(1) of this section and approval by the Administrator of the facility parameters, and prior to any of the parameters being exceeded, the owner or operator may submit a report to request modification of any facility parameter to the Administrator for approval. Each such request shall document any expected HAP emission change resulting from the change in parameter.

(k) As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in paragraph (b) of this section, an owner or operator may comply with the requirements in either paragraph (k)(1) or (2) of this section.

(1) An electronic copy of each record is instantly available at the terminal.

(i) The copy of each record in paragraph (k)(1) of this section is an exact duplicate image of the original paper record with certifying signatures.

(ii) The permitting authority is notified in writing that each terminal using this alternative is in compliance with paragraph (k)(1) of this section.

(2) For facilities that utilize a terminal automation system to prevent gasoline cargo tanks that do not have valid cargo tank vapor tightness documentation from loading (*e.g.,* via a card lock-out system), a copy of the documentation is made available (*e.g.,* via facsimile) for inspection by permitting authority representatives during the course of a site visit, or within a mutually agreeable time frame.

(i) The copy of each record in paragraph (k)(2) of this section is an exact duplicate image of the original paper record with certifying signatures.

(ii) The permitting authority is notified in writing that each terminal using this alternative is in compliance with paragraph (k)(2) of this section.

SECTION E.17 40 CFR Part 60, Subpart UU – Standards of Performance for Asphalt Process and Asphalt Roofing Manufacture

E.17.1 General Provisions Relating to NSPS Subpart UU [326 IAC 12-1] [40 CFR Part 60, Subpart UU]

Pursuant to 40 CFR Part 60.1(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the asphalt storage tanks 125, 126, 127, 129, 150, 569, 613, TK-SP-1, TK-SP-2, TK-LG-1 through TK-LG-9, and TK-LG-12 through TK-LG-17.

E.17.2 NSPS Subpart UU Requirements [40 CFR Part 60, Subpart UU] [326 IAC 12]

Pursuant to 40 CFR 60.470, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart UU, which are incorporated by reference as 326 IAC 12, for the asphalt storage tanks identified in Condition E.17.1 as specified below:

Subpart UU—Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture

§60.470 Applicability and designation of affected facilities.

(a) The affected facilities to which this subpart applies are each saturator and each mineral handling and storage facility at asphalt roofing plants; and each asphalt storage tank and each blowing still at asphalt processing plants, petroleum refineries, and asphalt roofing plants.

(b) Any saturator or mineral handling and storage facility under paragraph (a) of this section that commences construction or modification after November 18, 1980, is subject to the requirements of this subpart. Any asphalt storage tank or blowing still that processes and/or stores asphalt used for roofing only or for roofing and other purposes, and that commences construction or modification after November 18, 1980, is subject to the requirements of this subpart.

Any asphalt storage tank or blowing still that processes and/or stores only nonroofing asphalts and that commences construction or modification after May 26, 1981, is subject to the requirements of this subpart.

§ 60.471 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

Afterburner (A/B) means an exhaust gas incinerator used to control emissions of particulate matter.

Asphalt processing means the storage and blowing of asphalt.

Asphalt processing plant means a plant which blows asphalt for use in the manufacture of asphalt products.

Asphalt roofing plant means a plant which produces asphalt roofing products (shingles, roll roofing, siding, or saturated felt).

Asphalt storage tank means any tank used to store asphalt at asphalt roofing plants, petroleum refineries, and asphalt processing plants. Storage tanks containing cutback asphalts (asphalts diluted with solvents to reduce viscosity for low temperature applications) and emulsified asphalts (asphalts dispersed in water with an emulsifying agent) are not subject to this regulation.

Blowing still means the equipment in which air is blown through asphalt flux to change the softening point and penetration rate.

Catalyst means a substance which, when added to asphalt flux in a blowing still, alters the penetrating-softening point relationship or increases the rate of oxidation of the flux.

Coating blow means the process in which air is blown through hot asphalt flux to produce coating asphalt. The coating blow starts when the air is turned on and stops when the air is turned off.

Electrostatic precipitator (ESP) means an air pollution control device in which solid or liquid particulates in a gas stream are charged as they pass through an electric field and precipitated on a collection surface.

High velocity air filter (HVAF) means an air pollution control filtration device for the removal of sticky, oily, or liquid aerosol particulate matter from exhaust gas streams.

Mineral handling and storage facility means the areas in asphalt roofing plants in which minerals are unloaded from a carrier, the conveyor transfer points between the carrier and the storage silos, and the storage silos.

Saturator means the equipment in which asphalt is applied to felt to make asphalt roofing products. The term saturator includes the saturator, wet looper, and coater.

§60.472 Standards for particulate matter.

(c) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any asphalt storage tank exhaust gases with opacity greater than 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing. The control device shall not be bypassed during this 15-minute period. If, however, the emissions from any asphalt storage tank(s) are ducted to a control device for a saturator, the combined emissions shall meet the emission limit contained in paragraph (a) of this section during the time the saturator control device is operating. At any other time the asphalt storage tank(s) must meet the opacity limit specified above for storage tanks.

§ 60.473 Monitoring of operations.

(c) An owner or operator subject to the provisions of this subpart and using a control device not mentioned in paragraphs (a) or (b) of this section shall provide to the Administrator information describing the operation of the control device and the process parameter(s) which would indicate proper operation and maintenance of the device. The Administrator may require continuous monitoring and will determine the process parameters to be monitored.

§ 60.474 Test methods and procedures.

(c) The owner or operator shall determine compliance with the particulate matter standards in §60.472 as follows:

(5) Method 9 and the procedures in §60.11 shall be used to determine opacity.

E.17.3 Deadlines Relating to the Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture [40 CFR Part 60, Subpart UU]

The Permittee shall comply with the following requirements by the dates listed for storage tanks TK-SP-1, TK-SP-2, TK-LG-1 through TK-LG-9, and TK-LG-12 through TK-LG-17:

Requirement	Rule Citations	Deadline
Notification of the Date Construction (or Reconstruction) is Commenced	40 CFR 60.7(a)(1)	Within 30 days after commencement of construction
Notification of the Actual Date of Initial Startup	40 CFR 60.7(a)(3)	Within 15 days after date of initial startup
Notification of any Physical or Operational Change	40 CFR 60.7(a)(4)	60 days or more prior to commencement of change or as soon as practicable
Notification of the Anticipated Date for Conducting the Initial Opacity Observations Required by 40 CFR 60.11(e)(1)	40 CFR 60.7(a)(6)	30 days or more prior to opacity observations
Conduct Initial Opacity Observations Required by 40 CFR 60.11(e)(1)	40 CFR 60.11(e)(1)	60 days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of the facility

SECTION E.18 [RESERVED]

SECTION E.19 [RESERVED]

SECTION E.20 40 CFR Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants For Industrial, Commercial, and Institutional Boilers and Process Heaters

[RESERVED]

Section E.21 40 CFR 63, Subpart GGGGG—National Emission Standards for Hazardous Air Pollutants: Site Remediation

E.21.1 General Provisions Relating to NESHAP Subpart GGGGG [40 CFR Part 63, Subpart GGGGG] [326 IAC 20-1]

Pursuant to 40 CFR 63.7955, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, as specified in Table 3 of 40 CFR Part 63, Subpart GGGGG in accordance with the schedule in 40 CFR Part 63, Subpart GGGGG.

E.21.2 NESHAP Subpart GGGGG Requirements [40 CFR Part 63, Subpart GGGGG] [326 IAC 20-87]

The affected sources for the site remediation activities, including process vents, remediation material management units, and equipment components described in Section D.28 of this permit, are subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Site Remediation, (40 CFR 63, Subpart GGGGG), effective October 8, 2003. Pursuant to this rule, the Permittee must comply with the provisions of 40 CFR 63, Subpart GGGGG, which are incorporated by reference in 326 IAC 20-87, on and after October 8, 2006

What This Subpart Covers

§ 63.7880 What is the purpose of this subpart?

This subpart establishes national emissions limitations and work practice standards for hazardous air pollutants (HAP) emitted from site remediation activities. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emissions limitations and work practice standards.

§ 63.7881 Am I subject to this subpart?

(a) This subpart applies to you if you own or operate a facility at which you conduct a site remediation, as defined in §63.7957; and this site remediation, unless exempted under paragraph (b) or (c) of this section, meets all three of the following conditions specified in paragraphs (a)(1) through (3) of this section.

(1) Your site remediation cleans up a remediation material, as defined in §63.7957.

(2) Your site remediation is co-located at your facility with one or more other stationary sources that emit HAP and meet an affected source definition specified for a source category that is regulated by another subpart under 40 CFR part 63. This condition applies regardless whether or not the affected stationary source(s) at your facility is subject to the standards under the applicable subpart(s).

(3) Your facility is a major source of HAP as defined in §63.2, except as specified in paragraph (a)(3)(i) or (ii) of this section. A major source emits or has the potential to emit any single HAP at the rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year.

(i)

(ii)

(b) You are not subject to this subpart if your site remediation qualifies for any of one of the exemptions listed in paragraphs (b)(1) through (6) of this section.

(1) Your site remediation is not subject to this subpart if the site remediation only cleans up material that does not contain any of the HAP listed in Table 1 of this subpart.

(2) Your site remediation is not subject to this subpart if the site remediation will be performed under the authority of the Comprehensive Environmental Response and Compensation Liability Act (CERCLA) as a remedial action or a non time-critical removal action.

(3) Your site remediation is not subject to this subpart if the site remediation will be performed under a Resource Conservation and Recovery Act (RCRA) corrective action conducted at a treatment, storage and disposal facility (TSDF) that is either required by your permit issued by either the U.S. Environmental Protection Agency (EPA) or a State program authorized by the EPA under RCRA section 3006; required by orders authorized under RCRA; or required by orders authorized under RCRA section 7003.

(4)

(5)

(6) Your site remediation is not subject to this subpart if the site remediation is conducted at a research and development facility that meets the requirements under Clean Air Act (CAA) section 112(c)(7).

(c) Your site remediation activities are not subject to the requirements of this subpart, except for the recordkeeping requirements in this paragraph, provided that you meet the requirements specified in paragraphs (c)(1) through (c)(3) of this section.

(1) You determine that the total quantity of the HAP listed in Table 1 to this subpart that is contained in the remediation material excavated, extracted, pumped, or otherwise removed during all of the site remediations conducted at your facility is less than 1 megagram (Mg) annually. This exemption applies the 1 Mg limit on a facility-wide, annual basis, and there is no restriction to the number of site remediations that can be conducted during this period.

(2) You must prepare and maintain at your facility written documentation to support your determination that the total HAP quantity in your remediation materials for the year is less than 1 Mg. The documentation must include a description of your methodology and data used for determining the total HAP content of the remediation material.

(3) Your Title V permit does not have to be reopened or revised solely to include the recordkeeping requirement specified in paragraph (c)(2) of this section. However, the requirement must be included in your permit the next time the permit is renewed, reopened, or revised for another reason.

(d) Your site remediation is not subject to the requirements of this subpart if all remediation activities at your facility subject to this subpart are completed and you have notified the Administrator in writing that all remediation activities subject to this subpart are completed. You must maintain records of compliance, in accordance with §63.7953, for each remediation activity that was subject to this subpart. All future remediation activity meeting the applicability criteria in this section must comply with the requirements of this subpart.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69016, Nov. 29, 2006]

§ 63.7882 What site remediation sources at my facility does this subpart affect?

(a) This subpart applies to each new, reconstructed, or existing affected source for your site remediation as designated by paragraphs (a)(1) through (3) of this section.

(1) *Process vents.* The affected source is the entire group of process vents associated with the in-situ and ex-situ remediation processes used at your site to remove, destroy, degrade, transform, or immobilize hazardous substances in the remediation material subject to remediation. Examples of such in-situ remediation processes include, but are not limited to, soil vapor extraction and bioremediation processes. Examples of such ex-situ remediation processes include but are not limited to, thermal desorption, bioremediation, and air stripping processes.

(2) *Remediation material management units.* Remediation material management unit means a tank, surface impoundment, container, oil-water separator, organic-water separator, or transfer system, as defined in §63.7957, and is used at your site to manage remediation material. The affected source is the entire group of remediation material management units used for the site remediations at your site. For the purpose of this subpart, a tank or container that is also equipped with a vent that serves as a process vent,

as defined in §63.7957, is not a remediation material management unit, but instead this unit is considered to be a process vent affected source under paragraph (a)(1) of this section.

(3) *Equipment leaks.* The affected source is the entire group of equipment components (pumps, valves, etc.) used to manage remediation materials and meeting both of the conditions specified in paragraphs (a)(3)(i) and (ii) of this section. If either of these conditions do not apply to an equipment component, then that component is not part of the affected source for equipment leaks.

(i) The equipment component contains or contacts remediation material having a concentration of total HAP listed in Table 1 of this subpart equal to or greater than 10 percent by weight.

(ii) The equipment component is intended to operate for 300 hours or more during a calendar year in remediation material service, as defined in §63.7957.

(b) Each affected source for your site is existing if you commenced construction or reconstruction of the affected source before July 30, 2002.

(c) Each affected source for your site is new if you commenced construction or reconstruction of the affected source on or after July 30, 2002. An affected source is reconstructed if it meets the definition of reconstruction in §63.2.

§ 63.7883 When do I have to comply with this subpart?

(a) If you have an existing affected source, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you no later than October 9, 2006.

(b) If you have a new affected source that manages remediation material other than a radioactive mixed waste as defined in §63.7957, then you must meet the compliance date specified in paragraph (b)(1) or (2) of this section, as applicable to your affected source.

(1) If the affected source's initial startup date is on or before October 8, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you by October 8, 2003.

(2) If the affected source's initial startup date is after October 8, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you upon initial startup.

(c) If you have a new affected source that manages remediation material that is a radioactive mixed waste as defined in §63.7957, then you must meet the compliance date specified in paragraph (c)(1) or (2) of this section, as applicable to your affected source.

(1) If the affected source's initial startup date is on or before October 8, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you no later than October 9, 2006.

(2) If the affected source's initial startup date is after October 8, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you upon initial startup.

(d)

(e) You must meet the notification requirements, according to the schedule applicable to your facility, as specified in §63.7950 and in 40 CFR part 63, subpart A. Some of the notifications must be submitted before you are required to comply with the emissions limitations and work practice standards in this subpart.

General Standards

§ 63.7884 What are the general standards I must meet for each site remediation with affected sources?

(a) For each site remediation with an affected source designated under §63.7882, you must meet the standards specified in §§63.7885 through 63.7955, as applicable to your affected source, unless your site remediation meets the requirements for an exemption under paragraph (b) of this section.

(b) A site remediation that is completed within 30 consecutive calendar days according to the conditions in paragraphs (b)(1) through (3) of this section is not subject to the standards under paragraph (a) of this section. This exemption cannot be used for a site remediation involving the staged or intermittent cleanup of remediation material whereby the remediation activities at the site are started, stopped, and then re-started in a series of intervals, with durations less than 30-days per interval, when the time period from the beginning of the first interval to the end of the last interval exceeds 30 days.

(1) The 30 consecutive calendar day period for a site remediation that qualifies for this exemption is determined according to actions taken by you as defined in paragraphs (b)(1)(i) through (iii) of this section.

(i) The first day of the 30-day period is defined as the day on which you initiate any action that removes, destroys, degrades, transforms, immobilizes, or otherwise manages the remediation materials. The following activities, when completed before beginning this initial action, are not counted as part of the 30-day period: Activities to characterize the type and extent of the contamination by collecting and analyzing samples; activities to obtain permits from Federal, State, or local authorities to conduct the site remediation; activities to schedule workers and necessary equipment; and activities to arrange for contractor or third party assistance in performing the site remediation.

(ii) The last day of the 30-day period is defined as the day on which treatment or disposal of all of the remediation materials generated by the cleanup is completed such that the organic constituents in these materials no longer have a reasonable potential for volatilizing and being released to the atmosphere.

(iii) If treatment or disposal of the remediation materials is conducted at an off-site facility where the final treatment or disposal of the material cannot, or may not, be completed within the 30-day exemption period, then the shipment of all of the remediation material generated from your cleanup that is transferred to another party, or shipped to another facility, within the 30-day period, must be performed according to the applicable requirements specified in §63.7936.

(2) For the purpose of complying with paragraph (b)(1) of this section, if you ship or otherwise transfer the remediation material off-site you must include in the applicable shipping documentation, in addition to any notifications and certifications required under §63.7936, a statement that the shipped material was generated by a site remediation activity subject to the conditions of this exemption. The statement must include the date on which you initiated the site remediation activity generating the shipped remediation materials, as specified in paragraph (b)(1)(i) of this section, and the date 30 calendar days following your initiation date.

(3) You must prepare and maintain at your facility written documentation describing the exempted site remediation, and listing the initiation and completion dates for the site remediation.

[71 FR 69016, Nov. 29, 2006]

§ 63.7885 What are the general standards I must meet for my affected process vents?

(a) For the process vents that comprise the affected source designated under §63.7882, you must select and meet the requirements under one of the options specified in paragraph (b) of this section.

(b) For each affected process vent, except as exempted under paragraph (c) of this section, you must meet one of the options in paragraphs (b)(1) through (3) of this section.

(1) You control HAP emissions from the affected process vents according to the standards specified in §§63.7890 through 63.7893.

(2) You determine for the remediation material treated or managed by the process vented through the affected process vents that the average total volatile organic hazardous air pollutant (VOHAP) concentration, as defined in §63.7957, of this material is less than 10 parts per million by weight (ppmw). Determination of the VOHAP concentration is made using the procedures specified in §63.7943.

(3) If the process vent is also subject to another subpart under 40 CFR part 61 or 40 CFR part 63, you control emissions of the HAP listed in Table 1 of this subpart from the affected process vent in compliance with the standards specified in the applicable subpart. This means you are complying with all applicable emissions limitations and work practice standards under the other subpart (*e.g.,* you install and operate the required air pollution controls or have implemented the required work practice to reduce HAP emissions to levels specified by the applicable subpart). This provision does not apply to any exemption of the affected source from the emissions limitations and work practice standards allowed by the other applicable subpart.

(c) A process vent that meets the exemption requirements in paragraphs (c)(1) and (2) of this section is exempted from the requirements in paragraph (b) of this section.

(1) The process vent stream exiting the process vent meets the conditions in either paragraph (c)(1)(i) or (ii) of this section.

(i) The process vent stream flow rate is less than 0.005 cubic meters per minute (m^3 /min) at standard conditions (as defined in 40 CFR 63.2); or

(ii) The process vent stream flow rate is less than 6.0 m^3 /min at standard conditions (as defined in 40 CFR 63.2) and the total concentration of HAP listed in Table 1 of this subpart is less than 20 parts per million by volume (ppmv).

(2) You must demonstrate that the process vent stream meets the applicable exemption conditions in paragraph (c)(1) of this section using the procedures specified in §63.694(m). You must prepare and maintain documentation at your facility to support your determination of the process vent stream flow rate. This documentation must include identification of each process vent exempted under this paragraph and the test results used to determine the process vent stream flow rate and total HAP concentration, as applicable to the exemption conditions for your process vent. You must perform a new determination of the process vent stream flow rate and total HAP concentration, as applicable to the exemption conditions for your process vent, whenever changes to operation of the unit on which the process vent is used could cause the process vent stream conditions to exceed the maximum limits of the exemption.

§ 63.7886 What are the general standards I must meet for my affected remediation material management units?

(a) For each remediation material management unit that is part of an affected source designated by §63.7882, you must select and meet the requirements under one of the options specified in paragraph (b) of this section except for those remediation material management units exempted under paragraph (c) or (d) of this section.

(b) For each affected remediation material management unit, you must meet one of the options in paragraphs (b)(1) through (4) of this section.

(1) You control HAP emissions from the affected remediation material management unit according to the standards specified in paragraphs (b)(1)(i) through (v) of this section, as applicable to the unit.

(i) If the remediation material management unit is a tank, then you control HAP emissions according to the standards specified in §§63.7895 through 63.7898.

(ii) If the remediation material management unit is a container, then you control HAP emissions according to the standards specified in §§63.7900 through 63.7903.

(iii) If the remediation material management unit is a surface impoundment, then you control HAP emissions according to the standards specified in §§63.7905 through 63.7908.

(iv) If the remediation material management unit is an oil-water or organic-water separator, then you control HAP emissions according to the standards specified in §§63.7910 through 63.7913.

(v) If the remediation material management unit is a transfer system, then you control HAP emissions according to the standards specified in §§63.7915 through 63.7918.

(2) You determine that the average total VOHAP concentration, as defined in §63.7957, of the remediation material managed in the remediation material management unit material is less than 500 ppmw. You must follow the requirements in §63.7943 to demonstrate that the VOHAP concentration of the remediation material is less than 500 ppmw. Once the VOHAP concentration for a remediation material has been determined to be less than 500 ppmw, all remediation material management units downstream from the point of determination managing this material meet the requirements of this paragraph unless a remediation process is used that concentrates all, or part of, the remediation material being managed in the unit such that the VOHAP concentration of the material could increase. Any free product returned to the manufacturing process (*e.g.* , recovered oil returned to a storage tank at a refinery) is no longer subject to this subpart.

(3) If the remediation material management unit is also subject to another subpart under 40 CFR part 61 or 40 CFR part 63, you control emissions of the HAP listed in Table 1 of this subpart from the affected remediation material management unit in compliance with the standards specified in the applicable subpart. This means you are complying with all applicable emissions limitations and work practice standards under the other subpart (*e.g.,* you install and operate the required air pollution controls or have implemented the required work practice to reduce HAP emissions to levels specified by the applicable subpart). This provision does not apply to any exemption of the affected source from the emissions limitations and work practice standards allowed by the other applicable subpart.

(4) If the remediation material management unit is an open tank or surface impoundment used for a biological treatment process, you meet the requirements as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) You demonstrate that the biological treatment process conducted in the open tank or surface impoundment meets the performance levels specified in either §63.684(b)(4)(i) or (ii).

(ii) You monitor the biological treatment process conducted in the open tank or surface impoundment according to the requirements in §63.684(e)(4).

(c) A remediation material management unit is exempted from the requirements in paragraph (b) of this section if this unit is used for cleanup of radioactive mixed waste, as defined in §63.7957, that is subject to applicable regulations, directives, and other requirements under the Atomic Energy Act, the Nuclear Waste Policy Act, or the Waste Isolation Pilot Plant Land Withdrawal Act.

(d) One or a combination of remediation material management units may be exempted at your discretion from the requirements in paragraph (b) of this section provided that the total annual quantity of HAP listed in Table 1 of this subpart contained in the remediation material placed in all of the remediation material management units exempted under this paragraph is less than 1 Mg/yr. For each remediation material management unit you select to be exempted under this provision, you must meet the requirements in paragraphs (d)(1) and (2) of this section.

(1) You must designate each of the remediation material management units you are selecting to be exempted under this paragraph by either submitting to the Administrator a written notification identifying the exempt units or permanently marking the exempt units at the faculty site. If you choose to prepare and submit a written notification, this notification must include a site plan, process diagram, or other appropriate documentation identifying each of the exempt units. If you choose to permanently mark the exempt units, each exempt unit must be marked in such a manner that it can be readily identified as an exempt unit from the other remediation material management units located at the site.

(2) You must prepare an initial determination of the total annual HAP quantity in the remediation material placed in the units exempted under this paragraph. This determination is based on the total quantity of the

HAP listed in Table 1 of this subpart as determined at the point where the remediation material is placed in each exempted unit. You must perform a new determination whenever the extent of changes to the quantity or composition of the remediation material placed in the exempted units could cause the total annual HAP content in the remediation material to exceed 1 Mg/yr. You must maintain documentation to support the most recent determination of the total annual HAP quantity. This documentation must include the basis and data used for determining the organic HAP content of the remediation material.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69017, Nov. 29, 2006]

§ 63.7887 What are the general standards I must meet for my affected equipment leak sources?

(a) You must control HAP emissions from equipment leaks from each equipment component that is part of the affected source by implementing leak detection and control measures according to the standards specified in §§63.7920 through 63.7922 unless you elect to meet the requirements in paragraph (b) of this section.

(b) If the affected equipment leak source is also subject to another subpart in 40 CFR part 61 or 40 CFR part 63, you may control emissions of the HAP listed in Table 1 to this subpart from the affected equipment leak source in compliance with the standards specified in the other applicable subpart. This means you are complying with all applicable emissions limitations and work practice standards under the other subpart (*e.g.* , you implement leak detection and control measures to reduce HAP emissions as specified by the applicable subpart). This provision does not apply to any exemption of the affected source from the emissions limitations and work practice standards allowed by the other applicable subpart.

[71 FR 69017, Nov. 29, 2006]

§ 63.7888 How do I implement this rule at my facility using the cross-referenced requirements in other subparts?

(a) For the purposes of this subpart, when you read the term “HAP listed in Table 1 of this subpart” in a cross-referenced section under 40 CFR part 63, subpart DD—National Emission Standards for Hazardous Air Pollutants from Off-Site Waste and Recovery Operations, you should refer to Table 1 of this subpart.

(b) For the purposes of this subpart, when you read the term off-site material in a cross-referenced section under 40 CFR part 63, subpart DD—National Emission Standards for Hazardous Air Pollutants from Off-Site Waste and Recovery Operations you should substitute the term remediation material, as defined in §63.7957.

(c) For the purposes of this subpart, when you read the term regulated material in a cross-referenced section under 40 CFR part 63, subparts OO, PP, QQ, RR, TT, UU, WW, and VV you should substitute the term remediation material, as defined in §63.7957.

Process Vents
§ 63.7890 What emissions limitations and work practice standards must I meet for process vents?

(a) You must control HAP emissions from each new and existing process vent subject to §63.7885(b)(1) according to emissions limitations and work practice standards in this section that apply to your affected process vents.

(b) For your affected process vents, you must meet one of the facility-wide emission limit options specified in paragraphs (b)(1) through (4) of this section. If you have multiple affected process vent streams, you may comply with this paragraph using a combination of controlled and uncontrolled process vent streams that achieve the facility-wide emission limit that applies to you.

(1) Reduce from all affected process vents the total emissions of the HAP listed in Table 1 of this subpart to a level less than 1.4 kilograms per hour (kg/hr) and 2.8 Mg/yr (3.0 pounds per hour (lb/hr) and 3.1 tpy); or

(2) Reduce from all affected process vents the emissions of total organic compounds (TOC) (minus methane and ethane) to a level below 1.4 kg/hr and 2.8 Mg/yr (3.0 lb/hr and 3.1 tpy); or

(3) Reduce from all affected process vents the total emissions of the HAP listed in Table 1 of this subpart by 95 percent by weight or more; or

(4) Reduce from all affected process vents the emissions of TOC (minus methane and ethane) by 95 percent by weight or more.

(c) For each closed vent system and control device you use to comply with paragraph (b) of this section, you must meet the operating limit requirements and work practice standards in §63.7925(c) through (j) that apply to your closed vent system and control device.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69017, Nov. 29, 2006]

§ 63.7891 How do I demonstrate initial compliance with the emissions limitations and work practice standards for process vents?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7890(b) applicable to your affected process vents by meeting the requirements in paragraphs (b) through (d) of this section.

(b) You have measured or determined using the procedures for performance tests and design evaluations in §63.7941 that emission levels from all of your affected process vents meet the facility-wide emission limits in §63.7890(b) that apply to you, as follows in paragraphs (b)(1) through (4) of this section.

(1) If you elect to meet §63.7890(b)(1), you demonstrate that the total emissions of the HAP listed in Table 1 of this subpart from all affected process vents at your facility are less than 1.4 kg/hr and 2.8 Mg/yr (3.0 lb/hr and 3.1 tpy).

(2) If you elect to meet §63.7890(b)(2), you demonstrate that emissions of TOC (minus methane and ethane) from all affected process vents at your facility are less than 1.4 kg/hr and 2.8 Mg/yr (3.0 lb/hr and 3.1 tpy).

(3) If you elect to meet §63.7890(b)(3), you demonstrate that the total emissions of the HAP listed in Table 1 of this subpart from all affected process vents are reduced by 95 percent by weight or more.

(4) If you elect to meet §63.7890(b)(4), you demonstrate that the emissions of TOC (minus methane and ethane) from all affected process vents are reduced by 95 percent by weight or more.

(c) For each closed vent system and control device you use to comply with §63.7890(b), you have met each requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

(d) You have submitted a notification of compliance status according to the requirements in §63.7950.

§ 63.7892 What are my inspection and monitoring requirements for process vents?

For each closed vent system and control device you use to comply with §63.7890(b), you must monitor and inspect the closed vent system and control device according to the requirements in §63.7927 that apply to you.

§ 63.7893 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for process vents?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7890 applicable to your affected process vents by meeting the requirements in paragraphs (b) through (d) of this section.

(b) You must maintain emission levels from all of your affected process vents to meet the facilitywide emission limits in §63.7890(b) that apply to you, as specified in paragraphs (b)(1) through (4) of this section.

(1) If you elect to meet §63.7890(b)(1), you maintain the total emissions of the HAP listed in Table 1 of this subpart from all affected process vents at your facility are less than 1.4 kg/hr and 2.8 Mg/yr (3.0 lb/hr and 3.1 tpy).

(2) If you elect to meet §63.7890(b)(2), you maintain emissions of TOC (minus methane and ethane) from all affected process vents at your facility are less than 1.4 kg/hr and 2.8 Mg/yr (3.0 lb/hr and 3.1 tpy).

(3) If you elect to meet §63.7890(b)(3), you maintain the total emissions of the HAP listed in Table 1 of this subpart from all affected process vents are reduced by 95 percent by weight or more.

(4) If you elect to meet §63.7890(b)(4), you maintain that the emissions of TOC (minus methane and ethane) from all affected process vents are reduced by 95 percent by weight or more.

(c) For each closed vent system and control device you use to comply with §63.7890(b), you have met each requirement for demonstrating continuous compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7928.

(d) Keeping records to document continuous compliance with the requirements of this subpart according to the requirements in §63.7952.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69017, Nov. 29, 2006]

Tanks
§ 63.7895 What emissions limitations and work practice standards must I meet for tanks?

(a) You must control HAP emissions from each new and existing tank subject to §63.7886(b)(1)(i) according to emissions limitations and work practice standards in this section that apply to your affected tanks.

(b) For each affected tank, you must install and operate air pollution controls that meet the requirements in paragraphs (b)(1) through (4) of this section that apply to your tank.

(1) Unless your tank is used for a waste stabilization process, as defined in §63.7957, you must determine the maximum HAP vapor pressure (expressed in kilopascals (kPa)) of the remediation material placed in your tank using the procedures specified in §63.7944.

(2) If the maximum HAP vapor pressure of the remediation material you place in your tank is less than 76.6 kPa, then you must determine which tank level controls (*i.e.,* Tank Level 1 or Tank Level 2) apply to your tank as shown in Table 2 of this subpart, and based on your tank's design capacity (expressed in cubic meters (m^3)) and the maximum HAP vapor pressure of the remediation material you place in this tank. If your tank is required by Table 2 of this subpart to use Tank Level 1 controls, then you must meet the requirements in paragraph (c) of this section. If your tank is required by Table 2 of this subpart to use Tank Level 2 controls, then you must meet the requirements in paragraph (d) of this section

(3) If maximum HAP vapor pressure of the remediation material you place in your tank is 76.6 kPa or greater, then the tank must use one of the Tank Level 2 controls specified in paragraphs (d)(3) through (5) of this section. Use of floating roofs under paragraph (d)(1) or (2) of this section is not allowed for tanks managing these remediation materials.

(4) A tank used for a waste stabilization process, as defined in §63.7957, must use one of Tank Level 2 controls, as specified in paragraph (d) of this section, that is appropriate for your waste stabilization process.

(c) If you use Tank Level 1 controls, you must install and operate a fixed roof according to the requirements in §63.902. As an alternative to using this fixed roof, you may choose to use one of Tank Level 2 controls in paragraph (d) of this section.

(d) If you use Tank Level 2 controls, you must meet the requirements of one of the options in paragraphs (d)(1) through (5) of this section.

(1) Install and operate a fixed roof with an internal floating roof according to the requirements in §63.1063(a)(1)(i), (a)(2), and (b); or

(2) Install and operate an external floating roof according to the requirements in §63.1063(a)(1)(ii), (a)(2), and (b); or

(3) Install and operate a fixed roof vented through a closed vent system to a control device according to the requirements in §63.685(g). You must meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device; or

(4) Install and operate a pressure tank according to the requirements in §63.685(h); or

(5) Locate the tank inside a permanent total enclosure and vent emissions from the enclosure through a closed vent system to a control device that is an enclosed combustion device according to the requirements in §63.685(i). You must meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device.

(e) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your tanks. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

§ 63.7896 How do I demonstrate initial compliance with the emissions limitations and work practice standards for tanks?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7895 that apply to your affected tanks by meeting the requirements in paragraphs (b) through (h) of this section, as applicable to your containers.

(b) You have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(1) and (2) of this section.

(1) You have determined the applicable tank control levels specified in §63.7895(b) for the tanks to be used for your site remediation.

(2) You have determined, according to the procedures in §63.7944, and recorded the maximum HAP vapor pressure of the remediation material placed in each affected tank subject to §63.7886(b)(1)(i) that does not use Tank Level 2 controls.

(c) You must demonstrate initial compliance of each tank determined under paragraph (b) of this section to require Tank Level 1 controls if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(1) through (3) of this section.

(1) Each tank using Tank Level 1 controls is equipped with a fixed roof and closure devices according to the requirements in §63.902(b) and (c) and you have records documenting the design.

(2) You have performed an initial visual inspection of the fixed roof and closure devices for defects according to the requirements in §63.906(a) and you have records documenting the inspection results.

(3) You will operate the fixed roof and closure devices according to the requirements in §63.902.

(d) You must demonstrate initial compliance of each tank determined under paragraph (b) of this section to require Tank Level 2 controls and using a fixed roof with an internal floating roof according to §63.7895(d)(1) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (d)(1) through (3) of this section.

(1) Each tank is equipped with an internal floating roof that meets the requirements in §63.1063(a) and you have records documenting the design.

(2) You will operate the internal floating roof according to the requirements in §63.1063(b).

(3) You have performed an initial visual inspection according to the requirements in §63.1063(d)(1) and you have a record of the inspection results.

(e) You must demonstrate initial compliance of each tank determined under paragraph (b) of this section to require Tank Level 2 controls and using an external floating roof according to §63.7895(d)(2) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (e)(1) through (3) of this section.

(1) Each tank is equipped with an external floating roof that meets the requirements in §63.1063(a) and you have records documenting the design.

(2) You will operate the external floating roof according to the requirements in §63.1063(b).

(3) You have performed an initial seal gap measurement inspection according to the requirements in §63.1063(d)(3) and you have records of the measurement results.

(f) You must demonstrate initial compliance of each tank determined under paragraph (b) of this section to require Tank Level 2 controls and using a fixed roof vented to a control device according to §63.7895(d)(3) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (f)(1) through (4) of this section.

(1) Each tank is equipped with a fixed roof and closure devices according to the requirements in §63.902(b) and (c) and you have records documenting the design.

(2) You have performed an initial visual inspection of fixed roof and closure devices for defects according to the requirements in §63.695(b)(3) and you have records documenting the inspection results.

(3) You will operate the fixed roof and closure devices according to the requirements in §63.685(g).

(4) You have met each applicable requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

(g) You must demonstrate initial compliance of each tank determined under paragraph (b) of this section to require Tank Level 2 controls and operates as a pressure tank according to §63.7895(d)(4) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (g)(1) and (2) of this section.

(1) Each tank is designed to operate as a pressure tank according to the requirements in §63.685(h), and you have records documenting the design.

(2) You will operate the pressure tank and according to the requirements in §63.685(h).

(h) You must demonstrate initial compliance of each tank determined under paragraph (b) of this section to require Tank Level 2 controls and using a permanent total enclosure vented to an enclosed combustion device according to §63.7895(d)(5) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (h)(1) and (2) of this section.

(1) You have submitted as part of your notification of compliance status a signed statement that you have performed the verification procedure according to the requirements in §63.685(i), and you have records of the supporting calculations and measurements.

(2) You have met each applicable requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69016, Nov. 29, 2006]

§ 63.7897 What are my inspection and monitoring requirements for tanks?

(a) You must visually inspect each of your tanks using Tank Level 1 controls for defects at least annually according to the requirements in §63.906(a).

(b) You must inspect and monitor each of your tanks using Tank Level 2 controls according to the requirements in paragraphs (b)(1) through (5), as applicable to your tanks.

(1) If you use a fixed roof with an internal floating roof according to §63.7895(d)(1), you must visually inspect the fixed roof and internal floating roof according to the requirements in §63.1063(d)(1) and (2).

(2) If you use an external floating roof according to §63.7895(d)(2), you must visually inspect the external floating roof according to the requirements in §63.1063(d)(1) and inspect the seals according to the requirements in §63.1063(d)(2) and (3).

(3) If you use a fixed roof vented to a control device according to §63.7895(d)(3), you must meet requirements in paragraphs (b)(3)(i) and (ii) of this section.

(i) You must visually inspect the fixed roof and closure devices for defects according to the requirements in §63.695(b)(3).

(ii) You must monitor and inspect the closed vent system and control device according to the requirements in §63.7927 that apply to you.

(4) If you use a pressure tank according to §63.7895(d)(4), you must visually inspect the tank and its closure devices for defects at least annually to ensure they are operating according to the design requirements in §63.685(h).

(5) If you use a permanent total enclosure vented to an enclosed combustion device according to §63.7895(d)(5), you must meet requirements in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must perform the verification procedure for the permanent total enclosure at least annually according to the requirements in §63.685(i).

(ii) You must monitor and inspect the closed vent system and control device according to the requirements in §63.7927 that apply to you.

§ 63.7898 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for tanks?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7895 applicable to your affected tanks by meeting the requirements in paragraphs (b) through (d) of this section.

(b) You must demonstrate continuous compliance with the requirement to determine the applicable tank control level specified in §63.7895(b) for each affected tank by meeting the requirements in paragraphs (b)(1) through (3) of this section.

(1) Keeping records of the tank design capacity according to the requirements in §63.1065(a).

(2) For tanks subject to §63.7886(b)(1)(ii) and not using Tank Level 2 controls, meeting the requirements in paragraphs (b)(2)(i) and (ii) of this section.

(i) Keeping records of the maximum HAP vapor pressure determined according to the procedures in §63.7944 for the remediation material placed in each affected tank.

(ii) Performing a new determination of the maximum HAP vapor pressure whenever changes to the remediation material managed in the tank could potentially cause the maximum HAP vapor pressure to increase to a level that is equal to or greater than the maximum HAP vapor pressure for the tank design capacity specified in Table 2. You must keep records of each determination.

(3) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(c) You must demonstrate continuous compliance for each tank determined to require Tank Level 1 controls by meeting the requirements in paragraphs (c)(1) through (5) of this section.

(1) Operating and maintaining the fixed roof and closure devices according to the requirements in §63.902(c).

(2) Visually inspecting the fixed roof and closure devices for defects at least annually according to the requirements in §63.906(a).

(3) Repairing defects according to the requirements in §63.63.906(b).

(4) Recording the information specified in §63.907(a)(3) and (b).

(5) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(d) You must demonstrate continuous compliance for each tank determined to require Tank Level 2 controls and using a fixed roof with an internal floating roof according to §63.7895(d)(1) by meeting the requirements in paragraphs (d)(1) through (5) of this section.

(1) Operating and maintaining the internal floating roof according to the requirements in §63.1063(b).

(2) Visually inspecting the internal floating roof according to the requirements in §63.1063(d)(1) and (2).

(3) Repairing defects according to the requirements in §63.1063(e).

(4) Recording the information specified in §63.1065(b) through (d).

(5) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(e) You must demonstrate continuous compliance for each tank determined to require Tank Level 2 controls and using an external floating roof according to §63.7895(d)(2) by meeting the requirements in paragraphs (e)(1) through (5) of this section.

(1) Operating and maintaining the external floating roof according to the requirements in §63.1063(b).

(2) Visually inspecting the external floating roof according to the requirements in §63.1063(d)(1) and inspecting the seals according to the requirements in §63.1063(d)(2) and (3).

(3) Repairing defects according to the requirements in §63.1063(e).

(4) Recording the information specified in §63.1065(b) through (d).

(5) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(f) You must demonstrate continuous compliance for each tank determined to require Tank Level 2 controls and using a fixed roof vented to a control device according to §63.7895(d)(3) by meeting the requirements in paragraphs (f)(1) through (6) of this section.

(1) Operating and maintaining the fixed roof and closure devices according to the requirements in §63.685(g).

(2) Visually inspecting the fixed roof and closure devices for defects at least annually according to the requirements in §63.695(b)(3)(i).

(3) Repairing defects according to the requirements in §63.695(b)(4).

(4) Recording the information specified in §63.696(e).

(5) Meeting each applicable requirement for demonstrating continuous compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7928.

(6) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(g) You must demonstrate continuous compliance for each tank determined to require Tank Level 2 controls and operated as a pressure tank according to §63.7895(d)(4) by meeting the requirements in paragraphs (g)(1) through (3) of this section.

(1) Operating and maintaining the pressure tank and closure devices according to the requirements in §63.685(h).

(2) Visually inspecting each pressurized tank and closure devices for defects at least annually to ensure they are operating according to the design requirements in §63.685(h), and recording the results of each inspection.

(3) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(h) You must demonstrate continuous compliance for each tank determined to require Tank Level 2 controls and using a permanent total enclosure vented to an enclosed combustion device according to §63.7895(d)(5) by meeting the requirements in paragraphs (h)(1) through (4) of this section.

(1) Performing the verification procedure for the enclosure annually according to the requirements in §63.685(i).

(2) Recording the information specified in §63.696(f).

(3) Meeting each applicable requirement for demonstrating continuous compliance with the emissions limitations and work practice standards for a closed vent system and control device in §63.7928.

(4) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69017, Nov. 29, 2006]

Containers
§ 63.7900 What emissions limitations and work practice standards must I meet for containers?

(a) You must control HAP emissions from each new and existing container subject to §63.7886(b)(1)(ii) according to emissions limitations and work practice standards in this section that apply to your affected containers.

(b) For each container having a design capacity greater than 0.1 m^3 you must meet the requirements in paragraph (b)(1) or (2) of this section that apply to your container except at the times the container is used for treatment of remediation material by a waste stabilization process, as defined in §63.7957. As an alternative for any container subject to this paragraph, you may choose to meet the requirements in paragraph (d) of this section.

(1) If the design capacity of your container is less than or equal to 0.46 m^3 , then you must use controls according to the standards for Container Level 1 controls as specified in §63.922. As an alternative, you may choose to use controls according to either of the standards for Container Level 2 controls as specified in §63.923.

(2) If the design capacity of your container is greater than 0.46 m^3 , then you must use controls according to the standards for Container Level 2 controls as specified in §63.923 except as provided for in paragraph (b)(3) of this section.

(3) As an alternative to meeting the standards in paragraph (b)(2) of this section for containers with a capacity greater than 0.46 m^3 , if you determine that either of the conditions in paragraphs (b)(3)(i) or (ii) apply to the remediation material placed in your container, then you may use controls according to the standards for Container Level 1 controls as specified in §63.922.

(i) Vapor pressure of every organic constituent in the remediation material placed in your container is less than 0.3 kPa at 20 °C; or

(ii) Total concentration of the pure organic constituents having a vapor pressure greater than 0.3 kPa at 20 °C in the remediation material placed in your container is less than 20 percent by weight.

(c) At times when a container having a design capacity greater than 0.1 m^3 is used for treatment of a remediation material by a waste stabilization process as defined in §63.7957, you must control air emissions from the container during the process whenever the remediation material in the container is exposed to the atmosphere according to the standards for Container Level 3 controls as specified in §63.924. You must meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device.

(d) As an alternative to meeting the requirements in paragraph (b) of this section, you may choose to use controls on your container according to the standards for Container Level 3 controls as specified in §63.924. You must meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device.

(e) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your containers. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

§ 63.7901 How do I demonstrate initial compliance with the emissions limitations and work practice standards for containers?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7990 that apply to your affected containers by meeting the requirements in paragraphs (b) through (e) of this section, as applicable to your containers.

(b) You have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(1) and (2) of this section.

(1) You have determined the applicable container control levels specified in §63.7990 for the containers to be used for your site remediation.

(2) You have determined and recorded the maximum vapor pressure or total organic concentration for the remediation material placed in containers with a design capacity greater than 0.46 m^3 , and do not use Container Level 2 or Level 3 controls.

(c) You must demonstrate initial compliance of each container determined under paragraph (b) of this section to require Container Level 1 controls if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(1) and (2) of this section.

(1) Each container using Container Level 1 controls will be one of the containers specified in §63.922(b).

(2) You will operate each container cover and closure device according to the requirements in §63.922(d).

(d) You must demonstrate initial compliance of each container determined under paragraph (b) of this section to require Container Level 2 controls if you have submitted as part of your notification of

compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (d)(1) through (4) of this section.

(1) Each container using Container Level 2 controls will be one of the containers specified in §63.923(b).

(2) You will transfer remediation materials into and out of each container according to the procedures in §63.923(d).

(3) You will operate and maintain the container covers and closure devices according to the requirements in §63.923(d).

(4) You have records that the container meets the applicable U.S. Department of Transportation regulations, or you have conducted an initial test of each container for no detectable organic emissions using the procedures in §63.925(a), and have records documenting the test results, or you have demonstrated within the last 12 months that each container is vapor-tight according to the procedures in §63.925(a) and have records documenting the test results.

(e) You must demonstrate initial compliance of each container determined under paragraph (b) of this section to require Container Level 3 controls if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (e)(1) and (2) of this section.

(1) For each permanent total enclosure you use to comply with §63.7900, you have performed the verification procedure according to the requirements in §63.924(c)(1), and prepare records of the supporting calculations and measurements.

(2) You have met each applicable requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

§ 63.7902 What are my inspection and monitoring requirements for containers?

(a) You must inspect each container using Container Level 1 or Container Level 2 controls according to the requirements in §63.926(a).

(b) If you use Container Level 3 controls, you must meet requirements in paragraphs (b)(1) and (2) of this section, as applicable to your site remediation.

(1) You must perform the verification procedure for each permanent total enclosure annually according to the requirements in §63.924(c)(1).

(2) You must monitor and inspect each closed vent system and control device according to the requirements in §63.7927 that apply to you.

§ 63.7903 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for containers?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7990 applicable to your affected containers by meeting the requirements in paragraphs (b) through (e) of this section.

(b) You must demonstrate continuous compliance with the requirement to determine the applicable container control level specified in §63.7990(b) for each affected tank by meeting the requirements in paragraphs (b)(1) through (3) of this section.

(1) Keeping records of the quantity and design capacity for each type of container used for your site remediation and subject to §63.7886(b)(1)(ii).

(2) For containers subject to §63.7886(b)(1)(ii) with a design capacity greater than 0.46 m^3 and not using Container Level 2 or Container Level 3 controls, meeting the requirements in paragraphs (b)(2)(i) and (ii) of this section.

(i) Keeping records of the maximum vapor pressure or total organic concentration for the remediation material placed in the containers, as applicable to the conditions in §63.7900(b)(3)(i) or (ii) for which your containers qualify to use Container Level 1 controls.

(ii) Performing a new determination whenever changes to the remediation material placed in the containers could potentially cause the maximum vapor pressure or total organic concentration to increase to a level that is equal to or greater than the conditions specified in §63.7900(b)(3)(i) or (ii), as applicable to your containers. You must keep records of each determination.

(3) Keeping records to document compliance with the requirements according to the requirements in §63.7952.

(c) You must demonstrate continuous compliance for each container determined to require Container Level 1 controls by meeting the requirements in paragraphs (c)(1) through (5) of this section.

(1) Operating and maintaining covers for each container according to the requirements in §63.922(d) .

(2) Inspecting each container annually according to the requirements in §63.926(a)(2).

(3) Emptying or repairing each container according to the requirements in §63.926(a)(3).

(4) Keeping records of an inspection that includes the information in paragraphs (a)(4)(i) and (ii) of this section.

(i) Date of each inspection; and

(ii) If a defect is detected during an inspection, the location of the defect, a description of the defect, the date of detection, the corrective action taken to repair the defect, and if repair is delayed, the reason for any delay and the date completion of the repair is expected.

(5) Keeping records to document compliance with the requirements according to the requirements in §63.7952.

(d) You must demonstrate continuous compliance for each container determined to require Container Level 2 controls by meeting the requirements in paragraphs (d)(1) through (6) of this section.

(1) Transferring remediation material in and out of the container according to the requirements in §63.923(c).

(2) Operating and maintaining container covers according to the requirements in §63.923(d).

(3) Inspecting each container annually according to the requirements in §63.926(a)(2).

(4) Emptying or repairing containers according to the requirements in §63.926(a)(3).

(5) Keeping records of each inspection that include the information in paragraphs (d)(5)(i) and (ii) of this section.

(i) Date of each inspection; and

(ii) If a defect is detected during an inspection, the location of the defect, a description of the defect, the date of detection, the corrective action taken to repair the defect, and if repair is delayed, the reason for any delay and the date completion of the repair is expected.

(6) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(e) You must demonstrate continuous compliance for each container determined to require Container Level 3 controls by meeting the requirements in paragraphs (e)(1) through (4) of this section.

(1) Performing the verification procedure for the enclosure annually according to the requirements in §63.685(i).

(2) Recording the information specified in §63.696(f).

(3) Meeting each applicable requirement for demonstrating continuous compliance with the emissions limitations and work practice standards for a closed vent system and control device in §63.7928.

(4) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

Surface Impoundments

§ 63.7905 What emissions limitations or work practice standards must I meet for surface impoundments?

(a) You must control HAP emissions from each new and existing surface impoundment subject to §63.7886(b)(1)(iii) according to emissions limitations and work practice standards in this section that apply to your affected surface impoundments.

(b) For each affected surface impoundment, you must install and operate air pollution controls that meet either of the options in paragraphs (b)(1) or (2) of this section.

(1) Install and operate a floating membrane cover according to the requirements in §63.942; or

(2) Install and operate a cover vented through a closed vent system to a control device according to the requirements in §63.943. You must meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device.

(c) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your surface impoundments. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

§ 63.7906 How do I demonstrate initial compliance with the emissions limitations or work practice standards for surface impoundments?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7905 that apply to your affected surface impoundments by meeting the requirements in paragraphs (b) and (c) of this section, as applicable to your surface impoundments.

(b) You must demonstrate initial compliance of each surface impoundment using a floating membrane cover according to §63.7905(b)(1) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(1) through (3) of this section.

(1) You have installed a floating membrane cover and closure devices that meet the requirements in §63.942(b), and you have records documenting the design and installation.

(2) You will operate the cover and closure devices according to the requirements in §63.942(c).

(3) You have performed an initial visual inspection of each surface impoundment and closure devices according to the requirements in §63.946(a), and you have records documenting the inspection results.

(c) You must demonstrate initial compliance of each surface impoundment using a cover vented to a control device according to §63.7905(b)(2) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(1) through (4) of this section.

(1) You have installed a cover and closure devices that meet the requirements in §63.943(b), and have records documenting the design and installation.

(2) You will operate the cover and closure devices according to the requirements in §63.943(c).

(3) You have performed an initial visual inspection of each cover and closure devices according to the requirements in §63.946(b), and have records documenting the inspection results.

(4) You have met each applicable requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

§ 63.7907 What are my inspection and monitoring requirements for surface impoundments?

(a) If you use a floating membrane cover according to §63.7905(b)(1), you must visually inspect the floating membrane cover and its closure devices at least annually according to the requirements in §63.946(a).

(b) If you use a cover vented to a control device according to §63.7905(b)(2), you must meet requirements in paragraphs (b)(1) and (2) of this section.

(1) You must visually inspect the cover and its closure devices for defects according to the requirements in §63.946(b).

(2) You must monitor and inspect the closed vent system and control device according to the requirements in §63.7927 that apply to you.

§ 63.7908 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for surface impoundments?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7905 applicable to your affected surface impoundments by meeting the requirements in paragraphs (b) and (c) of this section as applicable to your surface impoundments.

(b) You must demonstrate continuous compliance for each surface impoundment using a floating membrane cover according to §63.7905(b)(1) by meeting the requirements in paragraphs (b)(1) through (5) of this section.

(1) Operating and maintaining the floating membrane cover and closure devices according to the requirements in §63.942(c).

(2) Visually inspecting the floating membrane cover and closure devices for defects at least annually according to the requirements in §63.946(a).

(3) Repairing defects according to the requirements in §63.946(c).

(4) Recording the information specified in §63.947(a)(2) and (a)(3).

(5) Keeping records to document compliance with the requirements according to the requirements in §63.7952.

(c) You must demonstrate continuous compliance for each surface impoundment using a cover vented to a control device according to §63.7905(b)(2) by meeting the requirements in paragraphs (c)(1) through (6) of this section.

(1) Operating and maintaining the cover and its closure devices according to the requirements in §63.943(c).

(2) Visually inspecting the cover and its closure devices for defects at least annually according to the requirements in §63.946(b).

(3) Repairing defects according to the requirements in §63.946(c).

(4) Recording the information specified in §63.947(a)(2) and (a)(3).

(5) Meeting each applicable requirement for demonstrating continuous compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7928.

(6) Keeping records to document compliance with the requirements according to the requirements in §63.7952.

Separators

§ 63.7910 What emissions limitations and work practice standards must I meet for separators?

(a) You must control HAP emissions from each new and existing oil-water separator and organic-water separator subject to §63.7886(b)(1)(iv) according to emissions limitations and work practice standards in this section that apply to your affected separators.

(b) For each affected separator, you must install and operate air pollution controls that meet one of the options in paragraphs (b)(1) through (3) of this section.

(1) Install and operate a floating roof according to the requirements in §63.1043. For portions of the separator where it is infeasible to install and operate a floating roof, such as over a weir mechanism, you must comply with the requirements specified in paragraph (b)(2) of this section.

(2) Install and operate a fixed roof vented through a closed vent system to a control device according to the requirements in §63.1044. You must meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device.

(3) Install and operate a pressurized separator according to the requirements in §63.1045.

(c) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your separators. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

§ 63.7911 How do I demonstrate initial compliance with the emissions limitations and work practice standards for separators?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7910 that apply to your affected separators by meeting the requirements in paragraphs (b) through (d) of this section, as applicable to your separators.

(b) You must demonstrate initial compliance of each separator using a floating roof according to §63.7910(b)(1) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(1) through (4) of this section.

(1) You have installed a floating roof and closure devices that meet the requirements in §63.1043(b), and you have records documenting the design and installation.

(2) You will operate the floating roof and closure devices according to the requirements in §63.1043(c).

(3) You have performed an initial seal gap measurement inspection using the procedures in §63.1046(b), and you have records documenting the measurement results.

(4) You have performed an initial visual inspection of the floating roof and closure devices for defects according to the requirements in §63.1047(b)(2), and you have records documenting the inspection results.

(5) For any portions of the separator using a fixed roof vented to a control device according to §63.7910(b)(1), you have met the requirements in paragraphs (c)(1) through (4) of this section.

(c) You must demonstrate initial compliance of each separator using a fixed roof vented to a control device according to §63.7910(b)(2) if you have submitted as part of your notification of compliance status,

specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(1) through (4) of this section.

(1) You have installed a fixed roof and closure devices that meet the requirements in §63.1042(b), and you have records documenting the design and installation.

(2) You will operate the fixed roof and its closure devices according to the requirements in §63.1042(c).

(3) You have performed an initial visual inspection of the fixed roof and closure devices for defects according to the requirements in §63.1047(a).

(4) You have met each applicable requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

(d) You must demonstrate initial compliance of each pressurized separator that operates as a closed system according to §63.7910(b)(3) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (d)(1) and (2) of this section.

(1) You have installed a pressurized separator that operates as a closed system according to the requirements in §63.1045(b)(1) and (b)(2), and you have records of the design and installation.

(2) You will operate the pressurized separator as a closed system according to the requirements in §63.1045(b)(3).

§ 63.7912 What are my inspection and monitoring requirements for separators?

(a) If you use a floating roof according to §63.7910(b)(1), you must meet requirements in paragraphs (a)(1) and (2) of this section.

(1) Measure the seal gaps at least annually according to the requirements in §63.1047(b)(1).

(2) Visually inspect the floating roof at least annually according to the requirements in §63.1047(b)(2).

(b) If you use a cover vented to a control device according to §63.7910(b)(1) or (2), you must meet requirements in paragraphs (b)(1) and (2) of this section.

(1) You must visually inspect the cover and its closure devices for defects according to the requirements in §63.1047(c).

(2) You must monitor and inspect the closed vent system and control device according to the requirements in §63.7927 that apply to you.

(c) If you use a pressurized separator that operates as a closed system according to §63.7910(b)(3), you must visually inspect each pressurized separator and closure devices for defects at least annually to ensure they are operating according to the design requirements in §63.1045(b).

§ 63.7913 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for separators?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7910 applicable to your affected separators by meeting the requirements in paragraphs (b) through (d) of this section as applicable to your surface impoundments.

(b) You must demonstrate continuous compliance for each separator using a floating roof according to §63.7910(b)(1) by meeting the requirements in paragraphs (b)(1) through (6) of this section.

(1) Operating and maintaining the floating roof according to the requirements in §63.1043(b).

(2) Performing seal gap measurement inspections at least annually according to the requirements in §63.1047(b)(1).

(3) Visually inspecting the floating roof at least annually according to the requirements in §63.1047(b)(2).

(4) Repairing defects according to the requirements in §63.1047(d).

(5) Recording the information specified in §63.1048(a) and (b).

(6) Keeping records to document compliance with the requirements according to the requirements in §63.7952.

(c) You must demonstrate continuous compliance for each separator using a fixed roof vented through a closed vent system to a control device according to §63.7910(b)(2) by meeting the requirements in paragraphs (c)(1) through (6) of this section.

(1) Operating and maintaining the fixed roof and its closure devices according to the requirements in §63.1042.

(2) Performing visual inspections of the fixed roof and its closure devices for defects at least annually according to the requirements in §63.1047(a).

(3) Repairing defects according to the requirements in §63.1047(d).

(4) Recording the information specified in §63.1048(a).

(5) Meeting each applicable requirement for demonstrating continuous compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7928.

(6) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(d) You must demonstrate continuous compliance for each pressurized separator operated as a closed system according to §63.7910(b)(3) by meeting the requirements in paragraphs (d)(1) and (2) of this section.

(1) Operating the pressurized separator at all times according to the requirements in §63.1045.

(2) Visually inspecting each pressurized tank and closure devices for defects at least annually to ensure they are operating according to the design requirements in §63.1045(b), and recording the results of each inspection.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69017, Nov. 29, 2006]

Transfer Systems
§ 63.7915 What emissions limitations and work practice standards must I meet for transfer systems?

(a) You must control HAP emissions from each new and existing transfer system subject to §63.7886(b)(1)(v) according to emissions limitations and work practice standards in this section that apply to your affected transfer systems.

(b) For each affected transfer system that is an individual drain system as defined in §63.7957, you must install and operate controls according to the requirements in §63.962.

(c) For each affected transfer system that is not an individual drain system as defined in §63.7957, you must use one of the transfer systems specified in paragraphs (c)(1) through (3) of this section.

(1) A transfer system that uses covers according to the requirements in §63.689(d).

(2) A transfer system that consists of continuous hard piping. All joints or seams between the pipe sections must be permanently or semi-permanently sealed (*e.g.* , a welded joint between two sections of metal pipe or a bolted and gasketed flange).

(3) A transfer system that is enclosed and vented through a closed vent system to a control device according to the requirements specified in paragraphs (c)(3)(i) and (ii) of this section.

(i) The transfer system is designed and operated such that an internal pressure in the vapor headspace in the enclosure is maintained at a level less than atmospheric pressure when the control device is operating, and

(ii) The closed vent system and control device are designed and operated to meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device.

(d) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your transfer systems. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

§ 63.7916 How do I demonstrate initial compliance with the emissions limitations and work practice standards for transfer systems?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7915 that apply to your affected transfer systems by meeting the requirements in paragraphs (b) through (e) of this section, as applicable to your transfer systems.

(b) You must demonstrate initial compliance of each individual drain system using controls according to §63.7915(b) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(1) through (3) of this section.

(1) You have installed air emission controls for each individual drain system and junction box according to the requirements in §63.962(a) and (b), and you have records documenting the installation and design.

(2) You will operate the air emission controls according to the requirements in §63.962(b)(5).

(3) You have performed an initial visual inspection of each individual drain system according to the requirements in §63.964(a), and you have records documenting the inspection results.

(c) You must demonstrate initial compliance of each transfer system using covers according to §63.7915(c)(1) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(1) through (3) of this section.

(1) Each transfer system is equipped with covers and closure devices according to the requirements in §63.689(d)(1) through (4), and you have records documenting the design and installation.

(2) You have performed an initial inspection of each cover and its closure devices for defects according to the requirements in §63.695(d)(1) through (5), and you have records documenting the inspection results.

(3) You will operate each cover and its closure devices according to the requirements in §63.689(5).

(d) You must demonstrate initial compliance of each transfer system that consists of hard piping according to §63.7915(c)(2) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (d)(1) and (2) of this section.

(1) You have installed a transfer system that consists entirely of hard piping and meets the requirements in §63.7915(c)(2), and you have records documenting the design and installation.

(2) You have performed an initial inspection of the entire transfer system to verify that all joints or seams between the pipe sections are permanently or semi-permanently sealed (*e.g.,* a welded joint between two

sections of metal pipe or a bolted and gasketed flange), and you have records documenting the inspection results.

(e) You must demonstrate initial compliance of each transfer system that is enclosed and vented to a control device according to §63.7915(e)(3) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (e)(1) and (2) of this section.

(1) You have installed a transfer system that is designed and operated such that an internal pressure in the vapor headspace in the enclosure is maintained at a level less than atmospheric pressure when the control device is operating, and you have records documenting the design and installation.

(2) You have met each applicable requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

§ 63.7917 What are my inspection and monitoring requirements for transfer systems?

(a) If you operate an individual drain system as a transfer system according to §63.7915(b), you must visually inspect each individual drain system at least annually according to the requirements in §63.964(a).

(b) If you operate a transfer system using covers according to §63.7915(c)(1), you must inspect each cover and its closure devices for defects according to the requirements in §63.695(d)(1) through (5).

(c) If you operate a transfer system consisting of hard piping according to §63.7915(c)(2), you must annually inspect the unburied portion of pipeline and all joints for leaks and other defects. In the event that a defect is detected, you must repair the leak or defect according to the requirements of paragraph (e) of this section.

(d) If you operate a transfer system that is enclosed and vented to a control device according to §63.7915(c)(3), you must meet requirements in paragraphs (d)(1) and (2) of this section.

(1) You must annually inspect all enclosure components (e.g., enclosure sections, closure devices, fans) for defects that would prevent an internal pressure in the vapor headspace in the enclosure from continuously being maintained at a level less than atmospheric pressure when the control device is operating. In the event that a defect is detected, you must repair the defect according to the requirements of paragraph (e) of this section.

(2) You must monitor and inspect the closed vent system and control device according to the requirements in §63.7927 that apply to you.

(e) If you are subject to paragraph (c) or (d) of this section, you must repair all detected defects as specified in paragraphs (e)(1) through (3) of this section.

(1) You must make first efforts at repair of the defect no later than 5 calendar days after detection and repair shall be completed as soon as possible but no later than 45 calendar days after detection except as provided in paragraph (e)(2) of this section.

(2) Repair of a defect may be delayed beyond 45 calendar days if you determine that repair of the defect requires emptying or temporary removal from service of the transfer system and no alternative transfer system is available at the site to accept the material normally handled by the system. In this case, you must repair the defect the next time the process or unit that is generating the material handled by the transfer system stops operation. Repair of the defect must be completed before the process or unit resumes operation.

(3) You must maintain a record of the defect repair according to the requirements specified in §63.7952.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

§ 63.7918 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for transfer systems?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7915 applicable to your affected transfer system by meeting the requirements in paragraphs (b) through (e) of this section as applicable to your transfer systems.

(b) You must demonstrate continuous compliance for each individual drain system using controls according to §63.7915(b) by meeting the requirements in paragraphs (b)(1) through (5) of this section.

(1) Operating and maintaining the air emission controls for individual drain systems according to the requirements in §63.962.

(2) Visually inspecting each individual drain system at least annually according to the requirements in §63.964(a).

(3) Repairing defects according to the requirements in §63.964(b).

(4) Recording the information specified in §63.965(a).

(5) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(c) You must demonstrate continuous compliance for each transfer system using covers according to §63.7915(c)(1) by meeting the requirements in paragraphs (c)(1) through (4) of this section.

(1) Operating and maintaining each cover and its closure devices according to the requirements in §63.689(d)(1) through (5).

(2) Performing inspections of each cover and its closure devices for defects at least annually according to the requirements in §63.695(d)(1) through (5).

(3) Repairing defects according to the requirements in §63.695(5)

(4) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(d) You must demonstrate continuous compliance for each transfer system that consists of hard piping according to §63.7915(c)(2) by meeting the requirements in paragraphs (d)(1) through (4) of this section.

(1) Operating and maintaining the pipeline to ensure that all joints or seams between the pipe sections remain permanently or semi-permanently sealed (*e.g.* , a welded joint between two sections of metal pipe or a bolted and gasketed flange).

(2) Inspecting the pipeline for defects at least annually according to the requirements in §63.7917(c).

(3) Repairing defects according to the requirements in §63.7917(e).

(4) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(e) You must demonstrate continuous compliance for each transfer system that is enclosed and vented to a control device according to §63.7915(c)(3) by meeting the requirements in paragraphs (e)(1) through (5) of this section.

(1) Operating and maintaining the enclosure to ensure that the internal pressure in the vapor headspace in the enclosure is maintained continuously at a level less than atmospheric pressure when the control device is operating.

(2) Inspecting the enclosure and its closure devices for defects at least annually according to the requirements in §63.7918(d).

(3) Repairing defects according to the requirements in §63.7918(e).

(4) Meeting each applicable requirement for demonstrating continuous compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7928.

(5) Keeping records to document compliance with the requirements according to the requirements in §63.7952.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

Equipment Leaks

§ 63.7920 What emissions limitations and work practice standards must I meet for equipment leaks?

(a) You must control HAP emissions from each new and existing equipment subject to §63.7887 according to emissions limitations and work practice standards in this section that apply to your affected equipment.

(b) For your affected equipment, you must meet the requirements in either paragraph (b)(1) or (2) of this section.

(1) Control equipment leaks according to all applicable requirements under 40 CFR part 63, subpart TT—National Emission Standards for Equipment Leaks—Control Level 1; or

(2) Control equipment leaks according to all applicable requirements under 40 CFR part 63, subpart UU—National Emission Standards for Equipment Leaks—Control Level 2.

(c) If you use a closed vent system and control device to comply with this section, as an alternative to meeting the standards in §63.1015 or §63.1034 for closed vent systems and control devices, you may elect to meet the requirements in §§63.7925 through 63.7928 that apply to your closed vent system and control device.

(d) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your equipment. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

§ 63.7921 How do I demonstrate initial compliance with the emissions limitations and work practice standards for equipment leaks?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7920 that apply to your affected equipment by meeting the requirements in paragraphs (b) and (c) of this section, as applicable to your affected sources.

(b) If you control equipment leaks according to the requirements under §63.7920(b)(1), you must demonstrate initial compliance if you have met the requirements in paragraphs (b)(1) and (2) of this section.

(1) You include the information required in §63.1018(a)(1) in your notification of compliance status report.

(2) You have submitted as part of your notification of compliance status a signed statement that:

(i) You will meet the requirements in §§63.1002 through 63.1016 that apply to your affected equipment.

(ii) You have identified the equipment subject to control according to the requirements in §63.1003, including equipment designated as unsafe to monitor, and have records supporting the determinations with a written plan for monitoring the equipment according to the requirements in §63.1003(c)(4).

(c) If you control equipment leaks according to the requirements under §63.7920(b)(2), you must demonstrate initial compliance if you have met the requirements in paragraphs (c)(1) and (2) of this section.

(1) You have included the information required in §63.1039(a) in your notification of compliance status report.

(2) You have submitted as part of your notification of compliance status a signed statement that:

(i) You will meet the requirements in §§63.1021 through 63.1037 that apply to your affected equipment.

(ii) You have identified the equipment subject to control according to the requirements in §63.1022, including equipment designated as unsafe to monitor, and have records supporting the determinations with a written plan for monitoring the equipment according to the requirements in §63.1022(c)(4).

§ 63.7922 How do I demonstrate continuous compliance with the work practice standards for equipment leaks?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7920 applicable to your affected equipment by meeting the requirements in paragraphs (b) through (d) of this section that apply to you.

(b) If you control equipment leaks according to the requirements under §63.7920(b)(1), you must demonstrate continuous compliance by inspecting, monitoring, repairing, and maintaining records according to the requirements in §§63.1002 through 63.1018 that apply to your affected equipment.

(c) If you control equipment leaks according to the requirements under §63.7920(b)(2), you must demonstrate continuous compliance by inspecting, monitoring, repairing, and maintaining records according to the requirements in §§63.1021 through 63.1039 that apply to your affected equipment.

(d) You must keep records to demonstrate compliance with the requirements according to the requirements in §63.7952.

Closed Vent Systems and Control Devices
§ 63.7925 What emissions limitations and work practice standards must I meet for closed vent systems and control devices?

(a) For each closed-vent system and control device you use to comply with requirements in §§63.7890 through 63.7922, as applicable to your affected sources, you must meet the emissions limitations and work practice standards in this section.

(b) Whenever gases or vapors containing HAP are vented through the closed-vent system to the control device, the control device must be operating except at those times listed in either paragraph (b)(1) or (2) of this section.

(1) The control device may be bypassed for the purpose of performing planned routine maintenance of the closed-vent system or control device in situations when the routine maintenance cannot be performed during periods that the emission point vented to the control device is shutdown. On an annual basis, the total time that the closed-vent system or control device is bypassed to perform routine maintenance must not exceed 240 hours per each calendar year.

(2) The control device may be bypassed for the purpose of correcting a malfunction of the closed-vent system or control device. You must perform the adjustments or repairs necessary to correct the malfunction as soon as practicable after the malfunction is detected.

(c) For each closed vent system, you must meet the work practice standards in §63.693(c).

(d) For each control device other than a flare or a control device used to comply with the facility-wide process vent emission limits in §63.7890(b), you must control HAP emissions to meet either of the emissions limits in paragraphs (d)(1) or (2) of this section except as provided for in paragraph (f) of this section.

(1) Reduce emissions of total HAP listed in Table 1 of this subpart or TOC (minus methane and ethane) from each control device by 95 percent by weight; or

(2) Limit the concentration of total HAP listed in Table 1 of this subpart or TOC (minus methane and ethane) from each combustion control device (a thermal incinerator, catalytic incinerator, boiler, or process heater) to 20 ppmv or less on a dry basis corrected to 3 percent oxygen.

(e) If you use a flare for your control device, then you must meet the requirements for flares in §63.11(b).

(f) If you use a process heater or boiler for your control device, then as alternative to meeting the emissions limits in paragraph (d) of this section you may choose to comply with one of the work practice standards in paragraphs (f)(1) through (3) of this section.

(1) Introduce the vent stream into the flame zone of the boiler or process heater and maintain the conditions in the combustion chamber at a residence time of 0.5 seconds or longer and at a temperature of 760 °C or higher; or

(2) Introduce the vent stream with the fuel that provides the predominate heat input to the boiler or process heater (*i.e.,* the primary fuel); or

(3) Introduce the vent stream to a boiler or process heater for which you either have been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H—Hazardous Waste Burned in Boilers and Industrial Furnaces; or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(g) For each control device other than a flare, you must meet each operating limit in paragraphs (g)(1) through (6) of this section that applies to your control device.

(1) If you use a regenerable carbon adsorption system, you must:

(i) Maintain the hourly average total regeneration stream mass flow during the adsorption bed regeneration cycle greater than or equal to the stream mass flow established in the design evaluation or performance test.

(ii) Maintain the hourly average temperature of the adsorption bed during regeneration (except during the cooling cycle) greater than or equal to the temperature established during the design evaluation or performance test.

(iii) Maintain the hourly average temperature of the adsorption bed after regeneration (and within 15 minutes after completing any cooling cycle) less than or equal to the temperature established during the design evaluation.

(iv) Maintain the frequency of regeneration greater than or equal to the frequency established during the design evaluation.

(2) If you use a nonregenerable carbon adsorption system, you must maintain the hourly average temperature of the adsorption bed less than or equal to the temperature established during the design evaluation or performance test.

(3) If you use a condenser, you must maintain the daily average condenser exit temperature less than or equal to the temperature established during the design evaluation or performance test.

(4) If you use a thermal incinerator, you must maintain the daily average firebox temperature greater than or equal to the temperature established in the design evaluation or during the performance test.

(5) If you use a catalytic incinerator, you must maintain the daily average temperature difference across the catalyst bed greater than or equal to the minimum temperature difference established during the performance test or design evaluation.

(6) If you use a boiler or process heater to comply with an emission limit in paragraph (d) of this section, you must maintain the daily average firebox temperature within the operating level established during the design evaluation or performance test.

(h) If you use a carbon adsorption system as your control, you must meet each work practice standard in paragraphs (h)(1) through (3) of this section that applies to your control device.

(1) If you use a regenerable carbon adsorption system, you must:

(i) Replace the existing adsorbent in each segment of the bed with an adsorbent that meets the replacement specifications established during the design evaluation before the age of the adsorbent exceeds the maximum allowable age established during the design evaluation.

(ii) Follow the disposal requirements for spent carbon in §63.693(d)(4).

(2) If you use a nonregenerable carbon adsorption system, you must:

(i) Replace the existing adsorbent in each segment of the bed with an adsorbent that meets the replacement specifications established during the design evaluation before the age of the adsorbent exceeds the maximum allowable age established during the design evaluation.

(ii) Meet the disposal requirements for spent carbon in §63.693(d)(4)(ii).

(3) If you use a nonregenerative carbon adsorption system, you may choose to comply with the requirements in paragraphs (h)(3)(i) and (ii) of this section as an alternative to the requirements in paragraph (h)(2) of this section. You must:

(i) Immediately replace the carbon canister or carbon in the control device when the monitoring device indicates breakthrough has occurred according to the requirements in §63.693(d)(4)(iii)(A), or replace the carbon canister or carbon in the control device at regular intervals according to the requirements in §63.693(d)(4)(iii)(B).

(ii) Follow the disposal requirements for spent carbon in §63.693(d)(4)(ii).

(i) If you use a catalytic incinerator, you must replace the existing catalyst bed with a bed that meets the replacement specifications before the age of the bed exceeds the maximum allowable age established in the design evaluation or during the performance test.

(j) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your closed vent systems and control devices. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

§ 63.7926 How do I demonstrate initial compliance with the emission limitations and work practice standards for closed vent systems and control devices?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in this subpart applicable to your closed vent system and control device by meeting the requirements in paragraphs (b) through (h) of this section that apply to your closed vent system and control device.

(b) You must demonstrate initial compliance with the closed vent system work practice standards in §63.7925(c) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(1) and (2) of this section.

(1) You have installed a closed vent system that meets the requirements in §63.695(c)(1) and (2), and you have records documenting the equipment design and installation.

(2) You have performed the initial inspection of the closed vent system according to the requirements in §63.695(c)(1)(i) or (ii), and you have records documenting the inspection results.

(c) You must demonstrate initial compliance of each control device subject to the emissions limits in §63.7925(d) with the applicable emissions limit in §63.7925(d) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(1) and (2) of this section that apply to you.

(1) For the emissions limit in §63.7925(d)(1), the emissions of total HAP listed in Table 1 of this subpart or TOC (minus methane and ethane) from the control device, measured or determined according to the procedures for performance tests and design evaluations in §63.7941, are reduced by at least 95 percent by weight.

(2) For the emissions limit in §63.7925(d)(2), the concentration of total HAP listed in Table 1 of this subpart or TOC (minus methane and ethane) from the combustion control device, measured by a performance test or determined by a design evaluation according to the procedures in §63.7941, do not exceed 20 ppmv on a dry basis corrected to 3 percent oxygen.

(d) You must demonstrate initial compliance of each control device subject to operating limits in §63.7925(g) with the applicable limits if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (d)(1) and (2) of this section.

(1) You have established an appropriate operating limit(s) for each of the operating parameter applicable to your control device as specified in §63.7925(g)(1) through (6).

(2) You have a record of the applicable operating parameter data during the performance test or design evaluation during which the emissions met the applicable limit.

(e) You must demonstrate initial compliance with the spent carbon replacement and disposal work practice standards for carbon adsorption systems in §63.7925(h) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you will comply with each work practice standard that applies to your carbon adsorption system.

(f) You must demonstrate initial compliance with the catalyst replacement work practice standards for catalytic incinerators in §63.7925(i) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you will comply with the specified work practice standard.

(g) You must demonstrate initial compliance of each flare with the work practice standards in §63.7925(e) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (g)(1) through (3) of this section.

(1) Each flare meets the requirements in §63.11(b).

(2) You have performed a visible emissions test, determined the net heating value of gas being combusted, and determined the flare exit velocity as required in §63.693(h)(2).

(3) You will operate each flare according to the requirements in §63.11(b).

(h) You must demonstrate initial compliance of each boiler or process heater with the work practice standards in §63.7925(f) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (h)(1) through (3) of this section.

(1) For the work practice standards in §63.7925(f)(1), you have records documenting that the boiler or process heater is designed to operate at a residence time of 0.5 seconds or greater and maintain the combustion zone temperature at 760 °C or greater.

(2) For the work practice standard in §63.7925(f)(2), you have records documenting that the vent stream is introduced with the fuel according to the requirements in §63.693(g)(1)(iv), or that the vent stream is introduced to a boiler or process heater that meets the requirements in §63.693(g)(1)(v).

(3) For the work practice standard in §63.7925(f)(3), you have records documenting you either have been issued a final permit under 40 CFR part 270 and your boiler or process heater complies with the requirements of 40 CFR part 266, subpart H—Hazardous Waste Burned in Boilers and Industrial

Furnaces; or has been certified in compliance with the interim status requirements of 40 CFR part 266, subpart H.

§ 63.7927 What are my inspection and monitoring requirements for closed vent systems and control devices?

(a) You must comply with the requirements in paragraphs (a)(1) and (2) of this section for each closed vent system.

(1) You must monitor and inspect each closed vent system according to the requirements in either paragraph (a)(1)(i) or (ii) of this section.

(i) You must monitor, inspect, and repair defects according to the requirements in §63.695(c)(1)(ii) through (c)(3); or

(ii) You must monitor and inspect the closed vent system according to the requirements in §63.172(f) through (j) and record the information in §63.181.

(2) If your closed vent system includes a bypass device, you must meet the requirements in either paragraph (a)(2)(i) or (ii) of this section.

(i) Use a flow indicator to determine if the presence of flow according to the requirements in §63.693(c)(2)(i); or

(ii) Use a seal or locking device and make monthly inspections as required by §63.693(c)(2)(ii).

(b) If you use a regenerable carbon adsorption system, you must meet the requirements in paragraphs (b)(1) through (3) of this section.

(1) Use a continuous parameter monitoring system (CPMS) to measure and record the hourly average total regeneration stream mass flow during each carbon adsorption cycle.

(2) Use a CPMS to measure and record the hourly average temperature of the adsorption bed during regeneration (except during the cooling cycle).

(3) Use a CPMS to measure and record the hourly average temperature of the adsorption bed after regeneration (and within 15 minutes after completing any cooling cycle).

(c) If you use a nonregenerable carbon adsorption system, you must use a CPMS to measure and record the hourly average temperature of the adsorption bed or you must monitor the concentration of organic compounds in the exhaust vent stream according to the requirements in §63.693(d)(4)(iii)(A).

(d) If you use a condenser, you must use a CPMS to measure and record the hourly average condenser exit temperature and determine and record the daily average condenser exit temperature.

(e) If you use a thermal incinerator, you must use a CPMS to measure and record the hourly average firebox temperature and determine and record the daily average firebox temperature.

(f) If you use a catalytic incinerator, you must use a CPMS with two temperature sensors to measure and record the hourly average temperature at the inlet of the catalyst bed, the hourly average temperature at the outlet of the catalyst bed, the hourly average temperature difference across the catalyst bed, and to determine and record the daily average temperature difference across the catalyst bed.

(g) If you use a boiler or process heater to meet an emission limitation, you must use a CPMS to measure and record the hourly average firebox temperature and determine and record the daily average firebox temperature.

(h) If you use a flare, you must monitor the operation of the flare using a heat sensing monitoring device according to the requirements in §63.693(h)(3).

(i) If you introduce the vent stream into the flame zone of a boiler or process heater according to the requirements in §63.7925(f)(1), you must use a CPMS to measure and record the combustion zone temperature.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

§ 63.7928 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for closed vent systems and control devices?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in this subpart applicable to your closed vent system and control device by meeting the requirements in paragraphs (b) through (j) of this section as applicable to your closed vent system and control device.

(b) You must demonstrate continuous compliance with the closed vent system work practice standards in §63.7925(c) by meeting the requirements in paragraphs (b)(1) through (7) of this section.

(1) For a closed vent system designed to operate with no detectable organic emissions, visually inspecting the closed vent system at least annually, monitoring after a repair or replacement using the procedures in §63.694(k), and monitoring at least annually according to the requirements in §63.695(c)(1)(ii).

(2) For a closed vent system designed to operate below atmospheric pressure, visually inspecting the closed vent system at least annually according to the requirements in §63.695(c)(2)(ii).

(3) Repairing defects according to the requirements in §63.695(c)(3).

(4) Keeping records of each inspection that include the information in paragraphs (b)(4)(i) through (iii) of this section:

(i) A closed vent system identification number (or other unique identification description you select).

(ii) Date of each inspection.

(iii) If a defect is detected during an inspection, the location of the defect, a description of the defect, the date of detection, the corrective action taken to repair the defect, and if repair is delayed, the reason for any delay and the date completion of the repair is expected.

(5) If you elect to monitor the closed vent system according to the requirements in §63.172(f) through (j), recording the information in §63.181.

(6) If the closed vent system is equipped with a flow indicator, recording the information in §63.693(c)(2)(i).

(7) If the closed vent system is equipped with a seal or locking device, visually inspecting the seal or closure mechanism at least monthly according to the requirements in §63.693(c)(2)(ii), and recording the results of each inspection.

(c) You must demonstrate continuous compliance of each control device subject to the emissions limits in §63.7925(d) with the applicable emissions limit in §63.7925(d) by meeting the requirements in paragraph (c)(1) or (2) of this section.

(1) For the emission limit in §63.7925(d)(1), maintaining the reduction in emissions of total HAP listed in Table 1 of this subpart or TOC (minus methane and ethane) from the control device at 95 percent by weight or greater.

(2) For the emission limit in §63.7925(d)(2), maintaining the concentration of total HAP listed in Table 1 of this subpart or TOC (minus methane and ethane) from the control device at 20 ppmv or less.

(d) You must demonstrate continuous compliance of each control device subject to operating limits in §63.7925(g) with the applicable limits by meeting the requirements in paragraphs (d)(1) through (4) of this section.

(1) Maintaining each operating limit according to the requirements in §63.7925(g) as applicable to the control device.

(2) Monitoring and inspecting each control device according to the requirements in §63.7927(b) through (i) as applicable to the control device.

(3) Operating and maintaining each continuous monitoring system according to the requirements in §63.7945, and collecting and reducing data according to the requirements in §63.7946.

(4) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(e) You must demonstrate continuous compliance with the spent carbon replacement and disposal work practice standards for regenerable carbon adsorption systems in §63.7925(h)(1) by meeting the requirements in paragraphs (e)(1) through (3) of this section.

(1) Replacing the adsorbent as required by §63.7925(h)(1)(i).

(2) Following the disposal requirements for spent carbon in §63.693(d)(4)(ii).

(3) Keeping records to document compliance with the requirements of the work practice standards.

(f) You must demonstrate continuous compliance with the spent carbon replacement and disposal work practice standards for nonregenerable carbon adsorption systems in §63.7925(h)(2) by meeting the requirements in paragraphs (f)(1) through (3) of this section.

(1) Replacing the adsorbent as required by the work practice standard in §63.7925(h)(2)(i).

(2) Following the disposal requirements for spent carbon in §63.693(d)(4)(ii).

(3) Keeping records to document compliance with the requirements of the work practice standards.

(g) You must demonstrate continuous compliance with the spent carbon replacement and disposal work practice standards for nonregenerable carbon adsorption systems in §63.7925(h)(3) by meeting the requirements in paragraphs (g)(1) through (3) of this section.

(1) Monitoring the concentration level of the organic compounds in the exhaust vent for the carbon adsorption system as required in §63.7927(c), immediately replacing the carbon canister or carbon in the control device when breakthrough is indicated by the monitoring device, and recording the date of breakthrough and carbon replacement. Or, you must replace the carbon canister or carbon in the control device at regular intervals and record the date of carbon replacement.

(2) Following the disposal requirements for spent carbon in §63.693(d)(4)(ii).

(3) Keeping records to document compliance with the requirements of the work practice standards.

(h) You must demonstrate continuous compliance with the catalyst replacement work practice standards for catalytic incinerators in §63.7925(i) by meeting the requirements in paragraphs (h)(1) and (2) of this section.

(1) Replacing the existing catalyst bed as required in §63.7925(i).

(2) Keeping records to document compliance with the requirements of the work practice standards.

(i) You must demonstrate continuous compliance of each flare with the work practice standards in §63.7925(e) by meeting the requirements in paragraphs (i)(1) through (5) of this section.

(1) Operating the flare with no visible emissions except for up to 5 minutes in any 2 consecutive hours according to the requirements in §63.11(b)(4).

(2) Monitoring the presence of a pilot flare according to the requirements in §63.7927(h) and maintaining a pilot flame and flare flame at all times that emissions are not vented to the flare according to the requirements in §63.11(b)(5).

(3) Operating the flare with an exit velocity according to the requirements in §63.11(b)(6) through (8).

(4) Operating the flare with a net heating value of the gas being combusted according to the requirements in §63.11(b)(6)(ii).

(5) Keeping records to document compliance with the requirements of the work practice standards.

(j) You must demonstrate continuous compliance of each boiler or process heater with the work practice standards in §63.7925(f) by meeting the requirements in paragraphs (j)(1) through (3) of this section.

(1) For the work practice standards in §63.7925(f)(1), you must demonstrate continuous compliance by meeting the requirements in paragraphs (j)(1)(i) through (iv).

(i) Maintaining conditions in the combustion chamber at a residence time of 0.5 seconds or longer and at a combustion zone temperature at 760 °C or greater whenever the vent stream is introduced to the flame zone of the boiler or process heater.

(ii) Monitoring each boiler or process heater according to the requirements in §63.7927(i).

(iii) Operating and maintaining each continuous monitoring system according to the requirements in §63.7945, and collecting and reducing data according to the requirements in §63.7946.

(iv) Keeping records to document compliance with residence time design requirement.

(2) For the work practice standards in §63.7925(f)(2), you maintain the boiler or process heater operations such that the vent stream is introduced with the fuel according to the requirements in §63.693(g)(1)(iv), or that the vent stream is introduced to a boiler or process heater that meets the requirements in §63.693(g)(1)(v).

(3) For the work practice standard in §63.7925(f)(3), you remain in compliance with all terms and conditions of the final permit under 40 CFR part 270 and your boiler or process heater complies with the requirements of 40 CFR part 266, subpart H—Hazardous Waste Burned in Boilers and Industrial Furnaces; or in compliance with the interim status requirements of 40 CFR part 266, subpart H, as applicable to your boiler or process heater.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

General Compliance Requirements
§ 63.7935 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emissions limitations (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

(b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in §63.6(e)(1)(i).

(c) You must develop a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).

(d) [Reserved]

(e) You must report each instance in which you did not meet each emissions limitation and each operating limit that applies to you. This includes periods of startup, shutdown, and malfunction. You must also report each instance in which you did not meet the requirements for work practice standards that apply to you. These instances are deviations from the emissions limitations and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7951.

(f) Consistent with §§63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with §63.6(e)(1). We will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

(g) For each monitoring system required in this section, you must develop and make available for inspection by the permitting authority, upon request, a site-specific monitoring plan that addresses the following:

(1) Installation of the continuous monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.,* on or downstream of the last control device).

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction system.

(3) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations).

(h) In your site-specific monitoring plan, you must also address the following:

(1) Ongoing operation and maintenance procedures according to the general requirements of §63.8(c)(1), (3), (4)(ii), (7), and (8).

(2) Ongoing data quality assurance procedures according to the general requirements of §63.8(d).

(3) Ongoing recordkeeping and reporting procedures according to the general requirements of §63.10(c), (e)(1), and (e)(2)(i).

(i) You must operate and maintain the continuous monitoring system according to the site-specific monitoring plan.

(j) You must conduct a performance evaluation of each continuous monitoring according to your site-specific monitoring plan.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 20468, Apr. 20, 2006; 71 FR 69018, Nov. 29, 2006]

§ 63.7936 What requirements must I meet if I transfer remediation material off-site to another facility?

(a) If you transfer to another facility a remediation material generated by your remediation activities and having an average total VOHAP concentration equal to or greater than 10 ppmw (as determined using the procedures specified in §63.7943), then you must transfer the remediation material to a facility that meets the requirements in paragraph (b) of this section. You must record the name, street address, and telephone number of the facility where you send this remediation material.

(b) You may elect to transfer the remediation material to one of the following facilities:

(1) A facility where your remediation material will be directly disposed in a landfill or other land disposal unit according to all applicable Federal and State requirements.

(2) A facility subject to 40 CFR part 63, subpart DD where the exemption under §63.680(b)(2)(iii) is waived and air emissions from the management of your remediation material at the facility are controlled according to all applicable requirements in the subpart for an off-site material. Prior to sending your remediation material, you must obtain a written statement from the owner or operator of the facility to which you send your remediation material acknowledging that the exemption under §63.680(b)(2)(iii) will be waived for all remediation material received at the facility from you and your material will be managed as an off-site material at the facility according to all applicable requirements. This statement must be signed by the responsible official of the receiving facility, provide the name and address of the receiving facility, and a copy sent to the appropriate EPA Regional Office at the addresses listed in 40 CFR 63.13.

(3) A facility where your remediation material will be managed according to all applicable requirements under this Subpart.

(i) You must prepare and include a notice with each shipment or transport of remediation material from your site. This notice must state that the remediation material contains organic HAP that are to be treated according to the provisions of this subpart. When the transport is continuous or ongoing (for example, discharge to a publicly owned treatment works), the notice must be submitted to the receiving facility owner or operator initially and whenever there is a change in the required treatment.

(ii) You may not transfer the remediation material unless the owner or operator of the facility receiving your remediation material has submitted to the EPA a written certification that he or she will manage remediation material received from you according to the requirements of §§63.7885 through 63.7957. The receiving facility owner or operator may revoke the written certification by sending a written statement to the EPA and to you providing at least 90 days notice that they rescind acceptance of responsibility for compliance with the regulatory provisions listed in this section. Upon expiration of the notice period, you may not transfer your remediation material to the facility.

(iii) By providing the written certification to the EPA, the receiving facility owner or operator accepts responsibility for compliance with the regulatory provisions listed in paragraph (b)(3) of this section with respect to any shipment of remediation material covered by the written certification. Failure to abide by any of those provisions with respect to such shipments may result in enforcement action by the EPA against the certifying entity according to the enforcement provisions applicable to violations of these provisions by owners or operators of sources.

(iv) Written certifications and revocation statements to the EPA from the receiving facility owner or operator must be signed by the responsible official of the receiving facility, provide the name and address of the receiving facility, and a copy sent to the appropriate EPA Regional Office at the addresses listed in 40 CFR 63.13. Such written certifications are not transferable.

(c) Acceptance by a facility owner or operator of remediation material from a site remediation subject to this Subpart does not, by itself, require the facility owner or operator to obtain a title V permit under 40 CFR 70.3 or 40 CFR 71.3.

§ 63.7937 How do I demonstrate initial compliance with the general standards?

(a) You must demonstrate initial compliance with the general standards in §§63.7884 through 63.7887 that apply to your affected sources by meeting the requirements in paragraphs (b) through (d) of this section, as applicable to you.

(b) You must demonstrate initial compliance with the general standards in §63.7885 that apply to your affected process vents by meeting the requirements in paragraphs (b)(1) through (4) of this section, as applicable to your process vents.

(1) If HAP emissions are controlled from the affected process vents according to the emission limitations and work practice standards specified in §63.7885(b)(1), you have met the initial compliance requirements in §63.7891.

(2) If the remediation material treated or managed by the process vented through the affected process vents has an average total VOHAP less than 10 ppmw according to §63.7885(b)(2), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have determined, according to the procedures §63.7943, and recorded the average VOHAP concentration of the remediation material placed in the affected remediation material management unit.

(3) If HAP emissions are controlled from the affected process vents to meet standards in another subpart under 40 CFR part 61 or 40 CFR part 63 according to §63.7885(b)(3), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(3)(i) and (ii) of this section.

(i) You include in your statement the citations for the specific emission limitations and work practice standards that apply to the process vents under the subpart in 40 CFR part 61 or 40 CFR part 63 that the vents are also subject.

(ii) You are complying with all applicable emissions limitations and work practice standards specified by the applicable subpart.

(4) For each process vent exempted according to §63.7885(c), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(4)(i) and (ii) of this section.

(i) You identify in your statement each process vent that qualifies for an exemption and the exemption conditions in §63.7885(c)(1)(i) or (ii) that apply to each exempted process vent.

(ii) You have performed the measurements and prepared the documentation required in §63.7885(c)(2) that demonstrates that each exempted process vent stream meets the applicable exemption conditions in §63.7885(c)(1).

(c) You must demonstrate initial compliance with the general standards in §63.7886 that apply to your affected remediation material management units by meeting the requirements in paragraphs (c)(1) through (6) of this section, as applicable to your remediation material management units.

(1) If the remediation material management unit uses air pollution controls according to the standards specified in §63.7886(b)(1), you have met the initial compliance requirements applicable to the remediation material management unit in §§63.7896, 63.7901, 63.7906, 63.7911, or 63.7816.

(2) If the remediation material managed in the affected remediation material management unit has an average total VOHAP concentration less than 500 ppmw according to §63.7886(b)(2), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have determined, according to the procedures in §63.7943, and recorded the average VOHAP concentration of the remediation material placed in the affected remediation material management unit.

(3) If HAP emissions are controlled from the affected remediation material management units to meet standards in another subpart under 40 CFR part 61 or 40 CFR part 63 according to §63.7886(b)(3), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(3)(i) and (ii) of this section.

(i) You include in your statement the citations for the specific emission limitations and work practice standards that apply to the remediation material management units under the subpart in 40 CFR part 61 or 40 CFR part 63 that the units are also subject.

(ii) You are complying with all applicable emissions limitations and work practice standards specified by the applicable subpart.

(4) If HAP emissions are controlled from the affected remediation material management unit that is an open tank or surface impoundment used for a biological treatment process according to §63.7886(b)(4), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(4)(i) and (ii) of this section.

(i) You have performed the measurements and prepared the documentation required in §63.7886(b)(4)(i) that demonstrates that each unit meets the applicable performance levels.

(ii) You will monitor the biological treatment process conducted in each unit according to the requirements in §63.684(e)(4).

(5) For each remediation material management unit used for cleanup of radioactive mixed waste and exempted according to §63.7886(c), you have submitted as part of your notification of compliance status,

specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(5)(i) and (ii) of this section.

(i) You include in your statement the citations for the specific requirements that apply to the remediation material management units under regulations, directives, and other requirements under the Atomic Energy Act, the Nuclear Waste Policy Act, or the Waste Isolation Pilot Plant Land Withdrawal Act.

(ii) You are complying with all requirements that apply to the remediation material management units under the applicable regulations or directives.

(6) For each remediation material management unit exempted according to §63.7886(d), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(6)(i) and (ii) of this section.

(i) You have designated according to the requirements in §63.7886(d)(1) each of the remediation material management units you are selecting to be exempted.

(ii) You have performed an initial determination and prepared the documentation required in §63.7886(d)(2) that demonstrates that the total annual HAP quantity (based on the HAP listed in Table 1 of this subpart) in the remediation material placed in all of the designated exempted remediation material management units will be less than 1 Mg/yr.

(d) You must demonstrate initial compliance with the general standards in §63.7887 that apply to your affected equipment leak sources by meeting the requirements in §63.7921.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

§ 63.7938 How do I demonstrate continuous compliance with the general standards?

(a) You must demonstrate continuous compliance with the general standards in §§63.7884 through 63.7887 that apply to your affected sources by meeting the requirements in paragraphs (b) through (d) of this section, as applicable to you.

(b) You have demonstrated continuous compliance with the general standards in §63.7885 that apply to your affected process vents by meeting the requirements in paragraphs (b)(1) through (4) of this section, as applicable to your process vents.

(1) If HAP emissions are controlled from the affected process vents according to the emission limitations and work practice standards specified in §63.7885(b)(1), you must demonstrate continuous compliance by meeting the requirements in §63.7893.

(2) If the remediation material treated or managed by the process vented through the affected process vents has an average total VOHAP less than 10 ppmw according to §63.7885(c)(1), you must demonstrate continuous compliance by performing a new determination and preparing new documentation as required in §63.7885(c)(2) to show that the total VOHAP concentration of the remediation material remains less than 10 ppmw.

(3) If HAP emissions are controlled from the affected process vents to meet standards in another subpart under 40 CFR part 61 or 40 CFR part 63 according to §63.7885(b)(3), you must demonstrate continuous compliance by complying with all applicable emissions limitations and work practice standards specified by the applicable subpart.

(4) For each process vent exempted according to §63.7885(c), you must demonstrate continuous compliance by performing new measurements and preparing new documentation as required in §63.7885(c)(2) that demonstrates that each exempted process vent stream meets the applicable exemption conditions in §63.7885(c)(1).

(c) You must demonstrate continuous compliance with the general standards in §63.7886 that apply to your affected remediation material management units by meeting the requirements in paragraphs (c)(1) through (6) of this section, as applicable to your remediation material management units.

(1) If the remediation material management unit uses air pollution controls according to the standards specified in §63.7886(b)(1), you must demonstrate continuous compliance by meeting the requirements applicable to the remediation material management unit in §§63.7898, 63.7903, 63.7908, 63.7913, or 63.7818.

(2) If the remediation material managed in the affected remediation material managements has an average total VOHAP concentration less than 500 ppmw according to §63.7886(b)(2), you must demonstrate continuous compliance by performing a new determination and preparing new documentation as required in §63.7886(c)(2) to show that the total VOHAP concentration of the remediation material remains less than 500 ppmw.

(3) If HAP emissions are controlled from the affected remediation material management units to meet standards in another subpart under 40 CFR part 61 or 40 CFR part 63 according to §63.7886(b)(3), you must demonstrate continuous compliance by meeting all applicable emissions limitations and work practice standards specified by the applicable subpart.

(4) If HAP emissions are controlled from the affected remediation material management unit that is an open tank or surface impoundment used for a biological treatment process according to §63.7886(b)(4), you must demonstrate continuous compliance by meeting the requirements in paragraphs (c)(4)(i) and (ii) of this section.

(i) Performing new measurements and preparing new documentation as required in §63.7886(4)(i) that demonstrates that each unit meets the applicable performance levels.

(ii) Monitoring the biological treatment process conducted in each unit according to the requirements in §63.7886(4)(i).

(5) For each remediation material management unit used for cleanup of radioactive mixed waste and exempted according to §63.7886(c), you must demonstrate continuous compliance by meeting all requirements that apply to the remediation material management units under the applicable regulations or directives.

(6) For each remediation material management unit exempted according to §63.7886(d), you must demonstrate continuous compliance by performing new measurements and preparing new documentation as required in §63.7886(d)(2) to show that the total annual HAP quantity (based on the HAP listed in Table 1 of this subpart) in the remediation material placed in all of the designated exempted remediation material management units remains less than 1 Mg/yr.

(d) You have demonstrated continuous compliance with the general standards in §63.7887 that apply to your affected equipment leak sources by meeting the requirements in §63.7923.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

Performance Tests
§ 63.7940 By what date must I conduct performance tests or other initial compliance demonstrations?

(a) You must conduct a performance test or design evaluation for each existing affected source within 180 calendar days after the compliance date that is specified in §63.7883.

(b) For each work practice standard that applies to you where initial compliance is not demonstrated using a performance test or design evaluation, you must demonstrate initial compliance within 30 calendar days after the compliance date that is specified in §63.7883 for your affected source.

(c) For new sources, you must conduct initial performance tests and other initial compliance demonstrations according to the provisions in §63.7(a)(2).

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69019, Nov. 29, 2006]

§ 63.7941 How do I conduct a performance test, design evaluation, or other type of initial compliance demonstration?

(a) You must conduct a performance test or design evaluation to demonstrate initial compliance for each new or existing affected source that is subject to an emission limit in this subpart. You must report the results of the performance test or design evaluation according to the requirements in §63.7950(e)(1).

(b) If you choose to conduct a performance test to demonstrate initial compliance, you must conduct the test according to the requirements in §63.7(e)(1) and paragraphs (b) (1) through (5) of this section.

(1) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(2) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).

(3) You must conduct each performance test using the test methods and procedures in §63.694(l).

(4) Follow the procedures in paragraphs (b)(4)(i) through (iii) of this section to determine compliance with the facility-wide total organic mass emissions rate in §63.7890(a)(1)(i).

(i) Determine compliance with the total organic mass flow rate using Equation 1 of this section as follows:

$$E_h = \left(0.0416 \times 10^{-6}\right) Q_{sd} \sum_{i=1}^{n} \left(C_i \times MW_i\right) \qquad \text{(Eq. 1)}$$

Where:

E_h= Total organic mass flow rate, kg/h;

Q_{sd}= Volumetric flow rate of gases entering or exiting control device (or exiting the process vent if no control device is used), as determined by Method 2 of 40 CFR part 60, appendix A, dscm/h;

n = Number of organic compounds in the vent gas;

C_i= Organic concentration in ppm, dry basis, of compound i in the vent gas, as determined by Method 18 of 40 CFR part 60, appendix A;

MW_i= Molecular weight of organic compound i in the vent gas,kg/kg-mol;

(ii) Determine compliance with the annual total organic emissions rate using Equation 2 of this section as follows:

$$E_A = E_h \times H \qquad \text{(Eq. 2)}$$

Where:

E_A= Total organic mass emissions rate, kilograms per year;

E_h= Total organic mass flow rate for the process vent, kg/h;

H = Total annual hours of operation for the affected unit, h.

(iii) Determine compliance with the total organic emissions limit from all affected process vents at the facility by summing the total hourly organic mass emissions rates ($E_h$as determined in Equation 1 of this

section) and summing the total annual organic mass emissions rates (E_A, as determined in Equation 2 of this section) for all affected process vents at the facility.

(5) Determine compliance with the 95 percent reduction limit in §63.7890(a)(2)(i) for the combination of all affected process vents at the facility using Equations 3 and 4 of this section to calculate control device inlet and outlet concentrations and Equation 5 of this section to calculate control device emission reductions for process vents as follows:

$$E_i = K_2 \left(\sum_{j=1}^{n} C_{ij} M_{ij} \right) Q_i \quad (Eq.\ 3)$$

$$E_o = K_2 \left(\sum_{j=1}^{n} C_{oj} M_{oj} \right) Q_o \quad (Eq.\ 4)$$

Where:

C_{ij}, C_{oj}= Concentration of sample component j of the gas stream at the inlet and outlet of the control device, dry basis, parts per million by volume. For uncontrolled vents, C_{ij}= $C_{oj}$and equal the concentration exiting the vent;

E_i, E_o= Mass rate of total organic compounds (TOC) (minus methane and ethane) or total HAP, from Table 1 of this subpart, at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour. For uncontrolled vents, E_i= $E_o$and equal the concentration exiting the vent;

M_{ij}, M_{oj}= Molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole. For uncontrolled vents, M_{ij}= $M_{oj}$and equal the gas stream molecular weight exiting the vent;

Q_i, Q_o= Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meters per minute (dscm/min). For uncontrolled vents, Q_i= $Q_o$and equals the flowrate exiting the vent;

K_2= Constant, 2.494×10^{-6}(parts per million)$^{-1}$(gram-mole per standard cubic meter)(kilogram/gram)(minute/hour, where standard temperature (gram-mole per standard cubic meter) is 20 °C);

n = the number of components in the sample.

$$R_v = \frac{\sum_{j=1}^{n} E_i - \sum_{j=1}^{n} E_o}{\sum_{j=1}^{n} E_i} \times 100 \quad (Eq.\ 5)$$

Where:

R_v= Overall emissions reduction for all affected process vents, percent

E_i= Mass rate of TOC (minus methane and ethane) or total HAP, from Table 1 of this subpart, at the inlet to the control device, or exiting the vent for uncontrolled vents, as calculated in this section, kilograms TOC per hour or kilograms HAP per hour;

E_o= Mass rate of TOC (minus methane and ethane) or total HAP, from Table 1 of this subpart, at the outlet to the control device, or exiting the vent for uncontrolled vents, as calculated in this section, kilograms TOC per hour or kilograms HAP per hour. For vents without a control device, E_o= E_i;

n = number of affected source process vents.

(c) If you use a carbon adsorption system, condenser, vapor incinerator, boiler, or process heater to meet an emission limit in this subpart, you may choose to perform a design evaluation to demonstrate initial compliance instead of a performance test. You must perform a design evaluation according to the general requirements in §63.693(b)(8) and the specific requirements in §63.693(d)(2)(ii) for a carbon adsorption system (including establishing carbon replacement schedules and associated requirements), §63.693(e)(2)(ii) for a condenser, §63.693(f)(2)(ii) for a vapor incinerator, or §63.693(g)(2)(i)(B) for a boiler or process heater.

(d) During the performance test or design evaluation, you must collect the appropriate operating parameter monitoring system data, average the operating parameter data over each test run, and set operating limits, whether a minimum or maximum value, based on the average of values for each of the three test runs. If you use a control device design analysis to demonstrate control device performance, then the minimum or maximum operating parameter value must be established based on the control device design analysis and supplemented, as necessary, by the control device manufacturer recommendations or other applicable information.

(e) If you control air emissions from an affected source by introducing the vent stream into the flame zone of a boiler or process heater according to the requirements in §63.693(g)(1)(iii), you must conduct a performance test or design evaluation to demonstrate that the boiler or process heater meets the applicable emission limit while operating at a residence time of 0.5 seconds or greater and at a combustion zone temperature of 760 °C or higher.

(f) You must conduct a performance evaluation for each continuous monitoring system according to the requirements in §63.8(e).

(g) If you are required to conduct a visual inspection of an affected source, you must conduct the inspection according to the procedures in §63.906(a)(1) for Tank Level 1 controls, §63.1063(d) for Tank Level 2 controls, §63.926(a) for Container Level 1 controls, §63.946(a) for a surface impoundment equipped with a floating membrane cover, §63.946(b) for a surface impoundment equipped with a cover and vented to a control device, §63.1047(a) for a separator with a fixed roof, §63.1047(c) for a separator equipped with a fixed roof and vented to a control device, §63.695(c)(1)(i) or (c)(2)(i) for a closed vent system, and §63.964(a) for individual drain systems.

(h) [Reserved]

(i) If you use Container Level 2 controls, you must conduct a test to demonstrate that the container operates with no detectable organic emissions or that the container is vapor-tight. You must conduct the test using Method 21 (40 CFR part 60, appendix A) and the procedures in §63.925(a) to demonstrate that the container operates with no detectable organic emissions or Method 27 (40 CFR part 60, appendix A) and the procedures in §63.925(b) to demonstrate that the container is vapor-tight.

(j) If you locate an affected source inside a permanent total enclosure that is vented to a control device, you must demonstrate that the enclosure meets the verification criteria in section 5 of Procedure T in 40 CFR 52.741, appendix B.

(k) If you use a fixed roof or a floating roof to control air emissions from a separator, you must conduct a test to demonstrate that the roof operates with no detectable organic emissions using Method 21 (40 CFR part 60, appendix A) and the procedures in §63.1046(a). If you use a floating roof, you also must measure the seal gaps according to the procedures in §63.1046(b).

(l) If you use a flare to control air emissions, you must conduct a visible emissions test using Method 22 in 40 CFR part 60, appendix A, and the procedures in §63.11(b)(4).

(m) For each initial compliance demonstration that requires a performance test or design evaluation, you must report the results in your notification of compliance status according to the requirements in §63.7950(e)(1). For each initial compliance demonstration that does not require a performance test or

design evaluation, you must submit a notification of compliance status according to the requirements in §63.7950(e)(2).

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69019, Nov. 29, 2006]

§ 63.7942 When must I conduct subsequent performance tests?

For non-flare control devices, you must conduct performance tests at any time the EPA requires you to according to §63.7(3).

§ 63.7943 How do I determine the average VOHAP concentration of my remediation material?

(a) General requirements. You must determine the average total VOHAP concentration of a remediation material using either direct measurement as specified in paragraph (b) of this section or by knowledge as specified in paragraph (c) of this section. These methods may be used to determine the average VOHAP concentration of any material listed in (a)(1) through (3) of this section.

(1) A single remediation material stream; or

(2) Two or more remediation material streams that are combined prior to, or within, a remediation material management unit or treatment process; or

(3) Remediation material that is combined with one or more non-remediation material streams prior to, or within, a remediation material management unit or treatment process.

(b) Direct measurement. To determine the average total VOHAP concentration of a remediation material using direct measurement, you must use the procedures in paragraphs (b)(1) through (3) of this section.

(1) Sampling. Samples of each material stream must be collected from the container, pipeline, or other device used to deliver each material stream prior to entering the remediation material management unit or treatment process in a manner such that volatilization of organics contained in the sample is minimized and an adequately representative sample is collected and maintained for analysis by the selected method.

(i) The averaging period to be used for determining the average total VOHAP concentration for the material stream on a mass-weighted average basis must be designated and recorded. The averaging period can represent any time interval that you determine is appropriate for the material stream but must not exceed 1 year. For streams that are combined, an averaging period representative for all streams must be selected.

(ii) No less than four samples must be collected to represent the complete range of HAP compositions and HAP quantities that occur in each material stream during the entire averaging period due to normal variations in the material stream(s). Examples of such normal variations are variation of the HAP concentration within a contamination area.

(iii) All samples must be collected and handled according to written procedures you prepare and document in a site sampling plan. This plan must describe the procedure by which representative samples of the material stream(s) are collected such that a minimum loss of organics occurs throughout the sample collection and handling process and by which sample integrity is maintained. A copy of the written sampling plan must be maintained on site in the facility operating records. An example of an acceptable sampling plan includes a plan incorporating sample collection and handling procedures according to the guidance found in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW–846 or Method 25D in 40 CFR part 60, appendix A.

(2) Analysis. Each collected sample must be prepared and analyzed according to either one of the methods listed in §63.694(b)(2)(ii), or any current EPA Contracts Lab Program method (or future revisions) capable of identifying all the HAP in Table 1 of this subpart.

(3) Calculations. The average total VOHAP concentration (C) on a mass-weighted basis must be calculated by using the results for all samples analyzed according to paragraph (b)(2) of this section and Equation 1 of this section as follows:

$$\bar{C} = \frac{1}{Q_T} \times \sum_{i=1}^{n} (Q_i \times C_i) \qquad (Eq.\ 1)$$

Where:

C= Average VOHAP concentration of the material on a mass-weighted basis, ppmw.

i = Individual sample “i” of the material.

n = Total number of samples of the material collected (at least 4 per stream) for the averaging period (not to exceed 1 year).

Q_i= Mass quantity of material stream represented by C_i, kilograms per hour (kg/hr).

Q_T= Total mass quantity of all material during the averaging period, kg/hr.

C_i= Measured VOHAP concentration of sample “i” as determined according to the requirements of paragraph (b)(2) of this section, ppmw.

(c) Knowledge of the material. To determine the average total VOHAP concentration of a remediation material using knowledge, you must use the procedures in paragraphs (c)(1) through (3) of this section.

(1) Documentation must be prepared that presents the information used as the basis for your knowledge of the material stream's average VOHAP concentration. Examples of information that may be used as the basis for knowledge include: material balances for the source(s) generating each material stream; species-specific chemical test data for the material stream from previous testing that are still applicable to the current material stream; test data for material from the contamination area(s) being remediated.

(2) If test data are used as the basis for knowledge, then you must document the test method, sampling protocol, and the means by which sampling variability and analytical variability are accounted for in the determination of the average VOHAP concentration. For example, you may use HAP concentration test data for the material stream that are validated according to Method 301 in 40 CFR part 63, appendix A as the basis for knowledge of the material. This information must be provided for each material stream where streams are combined.

(3) If you use species-specific chemical concentration test data as the basis for knowledge of the material, you may adjust the test data to the corresponding average VOHAP concentration value which would be obtained had the material samples been analyzed using Method 305. To adjust these data, the measured concentration for each individual HAP chemical species contained in the material is multiplied by the appropriate species-specific adjustment factor (f_{m305}) listed in Table 1 of this subpart.

(d) In the event that you and us disagree on a determination using knowledge of the average total VOHAP concentration for a remediation material, then the results from a determination of VOHAP concentration using direct measurement by Method 305 in 40 CFR part 60 appendix A, as specified in paragraph (b) of this section, will be used to determine compliance with the applicable requirements of this subpart. We may perform or request that you perform this determination using direct measurement.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69019, Nov. 29, 2006]

§ 63.7944 How do I determine the maximum HAP vapor pressure of my remediation material?

(a) You must determine the maximum HAP vapor pressure of your remediation material using either direct measurement as specified in paragraph (b) of this section or by knowledge as specified in paragraph (c) of this section.

(b) Direct measurement to determine the maximum HAP vapor pressure.

(1) Sampling. A sufficient number of samples must be collected to be representative of the remediation material contained in the tank. All samples must be collected and handled according to written procedures prepared by you and documented in a site sampling plan. This plan must describe the procedure by which representative samples of the remediation material are collected such that a minimum loss of organics occurs throughout the sample collection and handling process and by which sample integrity is maintained. A copy of the written sampling plan must be maintained on site in the facility site operating records. An example of an acceptable sampling plan includes a plan incorporating sample collection and handling procedures according to the guidance found in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW–846 or Method 25D in 40 CFR part 60, appendix A.

(2) Analysis. Any one of the following methods may be used to analyze the samples and compute the maximum HAP vapor pressure of the remediation material:

(i) Method 25E in 40 CFR part 60 appendix A;

(ii) Methods described in American Petroleum Institute Bulletin 2517, “Evaporation Loss from External Floating Roof Tanks,”;

(iii) Methods obtained from standard reference texts;

(iv) ASTM Method 2879–83; or

(v) Any other method approved by the Administrator.

(c) Use of knowledge to determine the maximum HAP vapor pressure. Documentation must be prepared and recorded that presents the information used as the basis for your knowledge that the maximum HAP vapor pressure of the remediation material is less than the maximum vapor pressure limit listed in Table 2 of this subpart for the applicable tank design capacity category.

(d) In the event that you and us disagree on a determination using knowledge of the maximum HAP vapor pressure of the remediation material, then the results from a determination of maximum HAP vapor pressure using direct measurement by Method 25E in 40 CFR part 60 appendix A, as specified in paragraph (b) of this section, will be used to determine compliance with the applicable requirements of this subpart. We may perform or request that you perform this determination using direct measurement.

Continuous Monitoring Systems
§ 63.7945 What are my monitoring installation, operation, and maintenance requirements?

(a) Each CPMS must meet the requirements in paragraphs (a)(1) through (4) of this section.

(1) Complete a minimum of one cycle of operation for each successive 15-minute period.

(2) To calculate a valid hourly value, you must have at least three of four equally spaced data values (or at least two, if that condition is included to allow for periodic calibration checks) for that hour from a CPMS that is not out of control according to the monitoring plan referenced in §63.7935.

(3) To calculate the average emissions for each averaging period, you must have at least 75 percent of the hourly averages for that period using only block hourly average values that are based on valid data (*i.e.,* not from out-of-control periods).

(4) Unless otherwise specified, each CPMS must determine the hourly average of all recorded readings and daily average, if required.

(b) You must record the results of each inspection, calibration, and validation check.

(c) You must conduct a performance evaluation for each CPMS according to the requirements in §63.8(e) and your site-specific monitoring plan.

§ 63.7946 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and your site-specific monitoring plan required in §63.7935.

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, out of control periods and required quality assurance or control activities in data averages and calculations used to report emissions or operating levels, nor may such data be used in fulfilling a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

§ 63.7947 What are my monitoring alternatives?

(a) As an alternative to the parametric monitoring required in this subpart, you may install, calibrate, and operate a continuous emission monitoring system (CEMS) to measure the control device outlet total organic emissions or organic HAP emissions concentration.

(1) The CEMS used on combustion control devices must include a diluent gas monitoring system (for O_2or CO_2) with the pollutant monitoring system in order to correct for dilution (*e.g.,* to 0 percent excess air).

(2) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data must be reduced as specified in §63.8(g)(2).

(3) You must conduct a performance evaluation of the CEMS according to the requirements in §63.8 and Performance Specification 8 (for a total organic emissions CEMS) or Performance Specification 9 (for a HAP emissions CEMS) and Performance Specification 3 (for an O_2or CO_2CEMS) of 40 CFR part 60, appendix B. The relative accuracy provision of Performance Specification 8, sections 2.4 and 3 need not be conducted.

(4) You must prepare a site-specific monitoring plan for operating, calibrating, and verifying the operation of your CEMS according to the requirements in §§63.8(c), (d), and (e).

(5) You must establish the emissions concentration operating limit according to paragraphs (a)(5)(i) and (ii) of this section.

(i) During the performance test, you must monitor and record the total organic or HAP emissions concentration at least once every 15 minutes during each of the three test runs.

(ii) Use the data collected during the performance test to calculate and record the average total organic or HAP emissions concentration maintained during the performance test. The average total organic or HAP emissions concentration, corrected for dilution as appropriate, is the maximum operating limit for your control device.

(b) You must maintain the daily (24-hour) average total organic or HAP emissions concentration in the exhaust vent stream of the control device outlet less than or equal to the site-specific operating limit established during the performance test.

Notification, Reports, and Records
§ 63.7950 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), 63.8(f)(4) and (6), and 63.9(b) through (h) that apply to you.

(b) As specified in §63.9(b)(2), if you start up your affected source before October 8, 2003, you must submit an Initial Notification not later than 120 calendar days after October 8, 2003.

(c) As specified in §63.9(b)(3), if you start up your new or reconstructed affected source on or after the effective date, you must submit an Initial Notification no later than 120 calendar days after initial startup.

(d) If you are required to conduct a performance test, you must submit a notification of intent to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin as required in §63.7(b)(1).

(e) If you are required to conduct a performance test, design evaluation, or other initial compliance demonstration, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration that includes a performance test or design evaluation, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test according to §63.10(d)(2). You must submit the complete design evaluation and supporting documentation.

(2) For each initial compliance demonstration that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th calendar day following the completion of the initial compliance demonstration.

(f) You must provide written notification to the Administrator of the alternative standard selected under §63.1006(b)(5) or (6) before implementing either of the provisions.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69019, Nov. 29, 2006]

§ 63.7951 What reports must I submit and when?

(a) Compliance report due dates. Unless the Administrator has approved a different schedule, you must submit a semiannual compliance report to your permitting authority according to the requirements specified in paragraphs (a)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.7883 and ending on June 30 or December 31, whichever date comes first after the compliance date that is specified for your affected source.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after your first compliance report is due.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of the dates specified in paragraphs (a)(1) through (4) of this section.

(b) Compliance report contents. Each compliance report must include the information specified in paragraphs (b)(1) through (3) of this section and, as applicable, paragraphs (b)(4) through (9) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a startup, shutdown, or malfunction during the reporting period and you took action consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in §63.10(d)(5)(i).

(5) If there were no deviations from any emissions limitations (including operating limit), work practice standards, or operation and maintenance requirements, a statement that there were no deviations from the emissions limitations, work practice standards, or operation and maintenance requirements during the reporting period.

(6) If there were no periods during which a continuous monitoring system (including a CPMS or CEMS) was out-of-control as specified by §63.8(c)(7), a statement that there were no periods during which the CPMS was out-of-control during the reporting period.

(7) For each deviation from an emissions limitation (including an operating limit) that occurs at an affected source for which you are not using a continuous monitoring system (including a CPMS or CEMS) to comply with an emissions limitation or work practice standard required in this subpart, the compliance report must contain the information specified in paragraphs (b)(1) through (4) and (b)(7)(i) and (ii) of this section. This requirement includes periods of startup, shutdown, and malfunction.

(i) The total operating time of each affected source during the reporting period.

(ii) Information on the number, duration, and cause of deviations (including unknown cause) as applicable and the corrective action taken.

(8) For each deviation from an emissions limitation (including an operating limit) or work practice standard occurring at an affected source where you are using a continuous monitoring system (including a CPMS or CEMS) to comply with the emissions limitations or work practice standard in this subpart, you must include the information specified in paragraphs (b)(1) through (4) and (b)(8)(i) through (xi) of this section. This requirement includes periods of startup, shutdown, and malfunction.

(i) The date and time that each malfunction started and stopped.

(ii) The date and time that each continuous monitoring system was inoperative, except for zero (low-level) and high-level checks.

(iii) The date, time, and duration that each continuous monitoring system was out-of-control, including the information in §63.8(c)(8).

(iv) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(v) A summary of the total duration of the deviations during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(vi) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and unknown causes.

(vii) A summary of the total duration of continuous monitoring system downtime during the reporting period and the total duration of continuous monitoring system downtime as a percent of the total source operating time during the reporting period.

(viii) A brief description of the process units.

(ix) A brief description of the continuous monitoring system.

(x) The date of the latest continuous monitoring system certification or audit.

(xi) A description of any changes in continuous monitoring systems, processes, or controls since the last reporting period.

(9) You must include the information on equipment leaks required in periodic reports by §63.1018(a) or §63.1039(b).

(c) Immediate startup, shutdown, and malfunction report. If you had a startup, shutdown, or malfunction during the semiannual reporting period that was not consistent with your startup, shutdown, and malfunction plan, you must submit an immediate startup, shutdown, and malfunction report according to the requirements of §63.10(d)(5)(ii) .

(d) Part 70 monitoring report. If you have obtained a title V operating permit for an affected source pursuant to 40 CFR part 70 or 40 CFR part 71, you must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If you submit a compliance report for an affected source along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all the required information concerning deviations from any emissions limitation or operation and maintenance requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation you may have to report deviations from permit requirements for an affected source to your permitting authority.

§ 63.7952 What records must I keep?

(a) You must keep the records specified in paragraphs (a)(1) through (4) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirements in §63.10(b)(1) and (b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startups, shutdowns, and malfunctions.

(3) Results of performance tests and performance evaluations as required by §63.10(b)(2)(viii).

(4) The records of initial and ongoing determinations for affected sources that are exempt from control requirements under this subpart.

(b) For each continuous monitoring system, you must keep the records as described in paragraphs (b)(1) and (2) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi) that apply to your continuous monitoring system.

(2) Performance evaluation plans, including previous (i.e., superseded) versions of the plan as required in §63.8(d)(3).

(c) You must keep the records required by this subpart to show continuous compliance with each emissions limitation, work practice standard, and operation and maintenance requirement that applies to you.

(d) You must record, on a semiannual basis, the information in §63.696(g) for planned routine maintenance of a control device for emissions from process vents.

§ 63.7953 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep your files of all information (including all reports and notifications) for 5 years following the date of each occurrence, measurement, maintenance, action taken to correct the cause of a deviation, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off-site for the remaining 3 years.

(d) If, after the remediation activity is completed, there is no other remediation activity at the facility, and you are no longer the owner of the facility, you may keep all records for the completed remediation activity at an off-site location provided you notify the Administrator in writing of the name, address and contact person for the off-site location.

Other Requirements and Information

§ 63.7955 What parts of the General Provisions apply to me?

Table 3 of this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§ 63.7956 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by us, the EPA, or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency, in addition to the EPA, has the authority to implement and enforce this subpart. You should contact your EPA Regional Office (see list in §63.13) to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under section 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that cannot be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the non-opacity emissions limitations and work practice standards in this subpart under §63.6(g).

(2) Approval of major changes to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major changes to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major changes to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69019, Nov. 29, 2006]

§ 63.7957 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in §63.2, and in this section. If a term is defined both in this section and in another subpart cross-referenced by this subpart, then the term will have the meaning given in this section for purposes of this subpart.

Boiler means an enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator or a process heater.

Closed vent system means a system that is not open to the atmosphere and is composed of hard-piping, ductwork, connections, and, if necessary, fans, blowers, or other flow-inducing device that conveys gas or vapor from an emissions point to a control device.

Closure device means a cap, hatch, lid, plug, seal, valve, or other type of fitting that prevents or reduces air pollutant emissions to the atmosphere by blocking an opening in a cover when the device is secured in the closed position. Closure devices include devices that are detachable from the cover (*e.g.,* a sampling port cap), manually operated (*e.g.,* a hinged access lid or hatch), or automatically operated (*e.g.,* a spring-loaded pressure relief valve).

Container means a portable unit used to hold material. Examples of containers include, but are not limited to drums, dumpsters, roll-off boxes, bulk cargo containers commonly known as portable tanks or totes,

cargo tank trucks, dump trucks, and rail cars. For the purpose of this subpart, a front-end loader, excavator, backhoe, or other type of self-propelled excavation equipment is not a container.

Continuous record means documentation of data values measured at least once every 15 minutes and recorded at the frequency specified in this subpart.

Continuous recorder means a data recording device that either records an instantaneous data value at least once every 15 minutes or records 15-minutes or more frequent block averages.

Control device means equipment used recovering, removing, oxidizing, or destroying organic vapors. Examples of such equipment include but are not limited to carbon adsorbers, condensers, vapor incinerators, flares, boilers, and process heaters.

Cover means a device that prevents or reduces air pollutant emissions to the atmosphere by forming a continuous barrier over the remediation material managed in a unit. A cover may have openings (such as access hatches, sampling ports, gauge wells) that are necessary for operation, inspection, maintenance, and repair of the unit on which the cover is used. A cover may be a separate piece of equipment which can be detached and removed from the unit (such as a tarp) or a cover may be formed by structural features permanently integrated into the design of the unit.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emissions limitation (including any operating limit), or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emissions limitation, (including any operating limit), or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Emissions limitation means any emissions limit, opacity limit, operating limit, or visible emissions limit.

Emissions point means an individual tank, surface impoundment, container, oil-water, organic-water separator, transfer system, vent, or enclosure.

Enclosure means a structure that surrounds a tank or container, captures organic vapors emitted from the tank or container, and vents the captured vapor through a closed vent system to a control device.

Equipment means each pump, pressure relief device, sampling connection system, valve, and connector used in remediation material service at a facility.

External floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a tank with no fixed roof.

Facility means all contiguous or adjoining property that is under common control including properties that are separated only by a road or other public right-of-way. Common control includes properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination thereof. A unit or group of units within a contiguous property that are not under common control (*e.g.,* a wastewater treatment unit located at the facility but is owned by a different company) is a different facility.

Fixed roof means a cover that is mounted on a unit in a stationary position and does not move with fluctuations in the level of the liquid managed in the unit.

Flame zone means the portion of the combustion chamber in a boiler or process heater occupied by the flame envelope.

Floating roof means a cover consisting of a double deck, pontoon single deck, or internal floating cover which rests upon and is supported by the liquid being contained, and is equipped with a continuous seal.

Flow indicator means a device that indicates whether gas is flowing, or whether the valve position would allow gas to flow in a bypass line.

Hard-piping means pipe or tubing that is manufactured and properly installed according to relevant standards and good engineering practices.

Individual drain system means a stationary system used to convey wastewater streams or residuals to a remediation material management unit or to discharge or disposal. The term includes hard-piping, all drains and junction boxes, together with their associated sewer lines and other junction boxes (*e.g.,* manholes, sumps, and lift stations) conveying wastewater streams or residuals. For the purpose of this subpart, an individual drain system is not a drain and collection system that is designed and operated for the sole purpose of collecting rainfall runoff (*e.g.,* stormwater sewer system) and is segregated from all other individual drain systems.

Internal floating roof means a cover that rests or floats on the liquid surface (but not necessarily in complete contact with it inside a tank that has a fixed roof).

Maximum HAP vapor pressure means the sum of the individual HAP equilibrium partial pressure exerted by remediation material at the temperature equal to either: the monthly average temperature as reported by the National Weather Service when the remediation material is stored or treated at ambient temperature; or the highest calendar-month average temperature of the remediation material when the remediation material is stored at temperatures above the ambient temperature or when the remediation material is stored or treated at temperatures below the ambient temperature. For the purpose of this subpart, maximum HAP vapor pressure is determined using the procedures specified in §63.7944.

No detectable organic emissions means no escape of organics to the atmosphere as determined using the procedure specified in §63.694(k).

Oil-water separator means a separator as defined for this subpart that is used to separate oil from water.

Operating parameter value means a minimum or maximum value established for a control device or treatment process parameter which, if achieved by itself or in combination with one or more other operating parameter values, determines that an owner or operator has complied with an applicable emissions limitation or standard.

Organic-water separator means a separator as defined for this subpart that is used to separate organics from water.

Process heater means an enclosed combustion device that transfers heat released by burning fuel directly to process streams or to heat transfer liquids other than water.

Process vent means any open-ended pipe, stack, duct, or other opening intended to allow the passage of gases, vapors, or fumes to the atmosphere and this passage is caused by mechanical means (such as compressors, vacuum-producing systems or fans) or by process-related means (such as volatilization produced by heating). For the purposes of this subpart, a process vent is neither a safety device (as defined in this section) nor a stack, duct or other opening used to exhaust combustion products from a boiler, furnace, heater, incinerator, or other combustion device.

Radioactive mixed waste means a material that contains both hazardous waste subject to RCRA and source, special nuclear, or by-product material subject to the Atomic Energy Act of 1954.

Remediation material means a material that contains one or more of the HAP listed in Table 1 of this subpart, and this material is one of the following:

(1) A material found in naturally occurring media such as soil, groundwater, surface water, sediments, or a mixture of such materials with liquids, sludges, or solids which is inseparable by simple mechanical removal processes and is made up primarily of media. This material does not include debris as defined in 40 CFR 268.2.

(2) A material found in intact or substantially intact containers, tanks, storage piles, or other storage units that requires clean up because this material poses a reasonable potential threat to contaminating media. Examples of these materials include, but are not limited to, solvents, oils, paints, and other volatile or semi-volatile organic liquids found in buried drums, cans, or other containers; gasoline, fuel oil, or other fuels in leaking underground storage tanks; and solid materials containing volatile or semi-volatile organics in unused or abandoned piles. Remediation material is not a waste or residue generated by routine equipment maintenance activities performed at a facility such as, but not limited to, tank bottoms and sludges removed during tank cleanouts; sludges and sediments removed from active wastewater treatment tanks, surface impoundments, or lagoons; spent catalyst removed from process equipment; residues removed from air pollution control equipment; and debris removed during heat exchanger and pipeline cleanouts.

Remediation material management unit means a tank, container, surface impoundment, oil-water separator, organic-water separator, or transfer system used to remove, destroy, degrade, transform, immobilize, or otherwise manage remediation material.

Remediation material service means any time when a pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, or instrumentation system contains or contacts remediation material.

Responsible official means responsible official as defined in 40 CFR 70.2.

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions to prevent physical damage or permanent deformation to equipment by venting gases or vapors during unsafe conditions resulting from an unplanned, accidental, or emergency event. For the purpose of this Subpart, a safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in this vapor headspace in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes, standard engineering codes and practices, or other requirements for the safe handling of flammable, combustible, explosive, reactive, or hazardous materials.

Separator means a remediation material management unit, generally a tank, used to separate oil or organics from water. A separator consists of not only the separation unit but also the forebay and other separator basins, skimmers, weirs, grit chambers, sludge hoppers, and bar screens that are located directly after the individual drain system and prior to any additional treatment units such as an air flotation unit clarifier or biological treatment unit. Examples of a separator include, but are not limited to, an API separator, parallel-plate interceptor, and corrugated-plate interceptor with the associated ancillary equipment.

Site remediation means one or more activities or processes used to remove, destroy, degrade, transform, immobilize, or otherwise manage remediation material. The monitoring or measuring of contamination levels in environmental media using wells or by sampling is not considered to be a site remediation.

Sludge means sludge as defined in §260.10 of this chapter.

Soil means unconsolidated earth material composing the superficial geologic strata (material overlying bedrock), consisting of clay, silt, sand, or gravel size particles (sizes as classified by the U.S. Soil Conservation Service), or a mixture of such materials with liquids, sludges, or solids which is inseparable by simple mechanical removal processes and is made up primarily of soil.

Stabilization process means any physical or chemical process used to either reduce the mobility of contaminants in media or eliminate free liquids as determined by Test Method 9095—Paint Filter Liquids Test in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW–846, Third Edition, September 1986, as amended by Update I, November 15, 1992. (As an alternative, you may use any more recent, updated version of Method 9095 approved by the EPA). A stabilization process includes mixing remediation material with binders or other materials, and curing the resulting remediation material and binder mixture. Other synonymous terms used to refer to this process are fixation or solidification. A stabilization process does not include the adding of absorbent materials to the surface of remediation material, without mixing, agitation, or subsequent curing, to absorb free liquid.

Surface impoundment means a unit that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to hold an accumulation of liquids. Examples of surface impoundments include holding, storage, settling, and aeration pits, ponds, and lagoons.

Tank means a stationary unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support and is designed to hold an accumulation of liquids or other materials.

Temperature monitoring device means a piece of equipment used to monitor temperature and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius (°C) or ±1.2 degrees °C, whichever value is greater.

Transfer system means a stationary system for which the predominant function is to convey liquids or solid materials from one point to another point within a waste management operation or recovery operation. For the purpose of this subpart, the conveyance of material using a container (as defined for this subpart) or a self-propelled vehicle (*e.g.* , a front-end loader) is not a transfer system. Examples of a transfer system include but are not limited to a pipeline, an individual drain system, a gravity-operated conveyor (such as a chute), and a mechanically-powered conveyor (such as a belt or screw conveyor).

Treatment process means a process in which remediation material is physically, chemically, thermally, or biologically treated to destroy, degrade, or remove hazardous air pollutants contained in the material. A treatment process can be composed of a single unit (*e.g.,* a steam stripper) or a series of units (*e.g.,* a wastewater treatment system). A treatment process can be used to treat one or more remediation material streams at the same time.

Volatile organic hazardous air pollutant (VOHAP) concentration means the fraction by weight of the HAP listed in Table 1 of this subpart that are contained in the remediation material as measured using Method 305, 40 CFR part 63, appendix A and expressed in terms of parts per million (ppm). As an alternative to using Method 305, 40 CFR part 63, appendix A, you may determine the HAP concentration of the remediation material using any one of the other test methods specified in §63.694(b)(2)(ii). When a test method specified in §63.694(b)(2)(ii) other than Method 305 in 40 CFR part 63, appendix A is used to determine the speciated HAP concentration of the contaminated material, the individual compound concentration may be adjusted by the corresponding f_{m305}listed in Table 1 of this subpart to determine a VOHAP concentration.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69019, Nov. 29, 2006]

Table 1 to Subpart GGGGG of Part 63.—List of Hazardous Air Pollutants

CAS No.[a]	Compound name	F_{m305}

75070	Acetaldehyde	1.000
75058	Acetonitrile	0.989
98862	Acetophenone	0.314
98862	Acetophenone	0.314
107028	Acrolein	1.000
107131	Acrylonitrile	0.999
107051	Allyl chloride	1.000
71432	Benzene (includes benzene in gasoline)	1.000
98077	Benzotrichloride (isomers and mixture)	0.958
100447	Benzyl chloride	1.000
92524	Biphenyl	0.864
542881	Bis(chloromethyl)ether[b]	0.999
75252	Bromoform	0.998
106990	1,3-Butadiene	1.000
75150	Carbon disulfide	1.000
56235	Carbon Tetrachloride	1.000
43581	Carbonyl sulfide	1.000
133904	Chloramben	0.633
108907	Chlorobenzene	1.000
67663	Chloroform	1.000
107302	Chloromethyl methyl ether[b]	1.000
126998	Chloroprene	1.000
98828	Cumene	1.000
94757	2,4-D, salts and esters	0.167
334883	Diazomethane[c]	0.999
132649	Dibenzofurans	0.967
96128	B1,2-Dibromo-3-chloropropane	1.000
106467	1,4-Dichlorobenzene(p)	1.000
107062	Dichloroethane (Ethylene dichloride)	1.000
111444	Dichloroethyl ether (Bis(2-chloroethylether)	0.757
542756	1,3-Dichloropropene	1.000
64675	Diethyl sulfate	0.0025
79447	Dimethyl carbamoyl chloride[c]	0.150

77781	Dimethyl sulfate	0.086
121697	N,N-Dimethylaniline	0.0008
51285	2,4-Dinitrophenol	0.0077
121142	2,4-Dinitrotoluene	0.0848
123911	1,4-Dioxane (1,4-Diethyleneoxide)	0.869
106898	Epichlorohydrin (1-Chloro-2,3-epoxypropane)	0.939
106887	1,2-Epoxybutane	1.000
140885	Ethyl acrylate	1.000
100414	Ethyl benzene	1.000
75003	Ethyl chloride (Chloroethane)	1.000
106934	Ethylene dibromide (Dibromoethane)	0.999
107062	Ethylene dichloride (1,2-Dichloroethane)	1.000
151564	Ethylene imine (Aziridine)	0.867
75218	Ethylene oxide	1.000
75343	Ethylidene dichloride (1,1-Dichloroethane)	1.000
	Glycol ethers[d] that have a Henry's Law Constant value equal to or greater than 0.01 Y/X(1.8×10^{-6} atm/gm-mole/m^3) at 25 °C	[e]
118741	Hexachlorobenzene	0.97
87683	Hexachlorobutadiene	0.88
67721	Hexachloroethane	0.499
110543	Hexane	1.000
78591	Isophorone	0.506
58899	Lindane (all isomers)	1.000
67561	Methanol	0.855
74839	Methyl bromide (Bromomethane)	1.000
74873	Methyl chloride (Choromethane)	1.000
71556	Methyl chloroform (1,1,1-Trichloroethane)	1.000
74884	Methyl iodide (Iodomethane)	1.000
108101	Methyl isobutyl ketone (Hexone)	0.979
624839	Methyl isocyanate	1.000
80626	Methyl methacrylate	0.999
1634044	Methyl tert butyl ether	1.000
75092	Methylene chloride (Dichloromethane)	1.000
91203	Naphthalene	0.994

98953	Nitrobenzene	0.394
79469	2-Nitropropane	0.989
82688	Pentachloronitrobenzene (Quintobenzene)	0.839
87865	Pentachlorophenol	0.0898
75445	Phosgene[c]	1.000
123386	Propionaldehyde	0.999
78875	Propylene dichloride (1,2-Dichloropropane)	1.000
75569	Propylene oxide	1.000
75558	1,2-Propylenimine (2-Methyl aziridine)	0.945
100425	Styrene	1.000
96093	Styrene oxide	0.830
79345	1,1,2,2-Tetrachloroethane	0.999
127184	Tetrachloroethylene (Perchloroethylene)	1.000
108883	Toluene	1.000
95534	o-Toluidine	0.152
120821	1,2,4-Trichlorobenzene	1.000
71556	1,1,1-Trichloroethane (Methyl chlorform)	1.000
79005	1,1,2-Trichloroethane (Vinyltrichloride)	1.000
79016	Trichloroethylene	1.000
95954	2,4,5-Trichlorophenol	0.0108
88062	2,4,6-Trichlorophenol	0.0132
121448	Triethylamine	1.000
540841	2,2,4-Trimethylpentane	1.000
108054	Vinyl acetate	1.000
593602	Vinyl bromide	1.000
75014	Vinyl chloride	1.000
75354	Vinylidene chloride (1,1-Dichloroethylene)	1.000
1330207	Xylenes (isomers and mixture)	1.000
95476	o-Xylenes	1.000
108383	m-Xylenes	1.000
106423	p-Xylenes	1.000

Notes:

F_{m305}Fraction measure factor in Method 305, 40 CFR 305 part 63, appendix A.

[a]CAS numbers refer to the Chemical Abstracts Services registry number assigned to specific compounds, isomers, or mixtures of compounds.

[b]Denotes a HAP that hydrolyzes quickly in water, but the hydrolysis products are also HAP chemicals.

[c]Denotes a HAP that may react violently with water.

[d]Denotes a HAP that hydrolyzes slowly in water.

[e]The F_{m305}factors for some of the more common glycol 305 ethers can be obtained by contacting the Waste and Chemical Processes Group, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

[71 FR 69020, Nov. 29, 2006]

Table 2 to Subpart GGGGG of Part 63—Control Levels as Required by §63.7895(a) for Tanks Managing Remediation Material With a Maximum HAP Vapor Pressure Less Than 76.6kPa

If your tank design capacity is . . .	And the maximum HAP vapor pressure of the remediation material placed in your tank is . . .	Then your tank must use . . .
1. Less than 38 m^3	Less than 76.6 kPa	Tank Level 1 controls under §63.7895(b).
2. At least 38 m^3but less than 151 m^3	Less than 13.1 kPa	Tank Level 1 controls under §63.7895(b).
3. 151 m^3or greater	Less than 0.7 kPa	Tank Level 1 controls under §63.7895(b).
4. at least 38 m^3but less than 151 m^3	13.1 kPa or greater	Tank Level 2 controls under §63.7895(c).
5. 151 m^3or greater	0.7 kPa or greater	Tank Level 2 controls under §63.7895(c)

Table 3 to Subpart GGGGG of Part 63—Applicability of General Provisions to Subpart GGGGG

As stated in §63.7940, you must comply with the applicable General Provisions requirements according to the following table:

Citation	Subject	Brief description	Applies to subpart GGGGG
§63.1	Applicability	Initial Applicability Determination; Applicability After Standard Established; Permit Requirements; Extensions, Notifications	Yes.
§63.2	Definitions	Definitions for part 63 standards	Yes.
§63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.
§63.4	Prohibited Activities	Prohibited Activities; Compliance date; Circumvention, Severability	Yes.
§63.5	Construction/Reconstruction	Applicability; applications; approvals	Yes.
§63.6(a)	Applicability	General Provisions (GP) apply unless compliance extension GP apply to area sources that become major	Yes.
§63.6(b)(1)–(4)	Compliance Dates for New and	Standards apply at effective date; 3 years	Yes.

	Reconstructed sources	after effective date; upon startup; 10 years after construction or reconstruction commences for 112(f)	
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source	Yes.
§63.6(c)(1)–(2)	Compliance Dates for Existing Sources	Comply according to date in subpart, which must be no later than 3 years after effective date. For 112(f) standards, comply within 90 days of effective date unless compliance extension	Yes.
§63.6(c)(3)–(4)	[Reserved]		
§63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Area sources that become major must comply with major source standards by date indicated in subpart or by equivalent time period (for example, 3 years)	Yes.
§63.6(d)	[Reserved]		
§63.6(e)(1)–(2)	Operation & Maintenance	Operate to minimize emissions at all times. Correct malfunctions as soon as practicable. Operation and maintenance requirements independently enforceable; information Administrator will use to determine if operation and maintenance requirements were met	Yes.
§63.6(e)(3)	Startup, Shutdown, and Malfunction Plan (SSMP)	Requirement for startup, shutdown and malfunction (SSM) and SSMP. Content of SSMP	Yes with the exception of containers using either Level 1 or Level 2 controls.
§63.6(f)(1)	Compliance Except During SSM	You must comply with emissions standards at all times except during SSM	Yes.
§63.6(f)(2)–(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection	Yes.
§63.6(g)(1)–(3)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§63.6(h)	Opacity/Visible Emissions (VE) Standards	Requirements for opacity and visible emissions limits	No. No opacity standards.
§63.6(i)(1)–(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension	Yes.

§63.6(j)	Presidential Compliance Exemption	President may exempt source category from requirement to comply with final rule	Yes.
§63.7(a)(1)–(2)	Performance Test Dates	Dates for Conducting Initial Performance Testing and Other Compliance Demonstrations. Must conduct 180 days after first subject to final rule	Yes.
§63.7(a)(3)	CAA Section 114 Authority	Administrator may require a performance test under CAA section 114 at any time	Yes.
§63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test	Yes.
§63.7(b)(2)	Notification of Rescheduling	If rescheduling a performance test is necessary, must notify Administrator 5 days before scheduled date of rescheduled date	Yes.
§63.7(c)	Quality Assurance/Test Plan	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with: Test plan approval procedures; performance audit requirements; internal and external QA procedures for testing	Yes.
§63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
§63.7(e)(1)	Conditions for Conducting Performance Tests	Performance tests must be conducted under representative conditions. Cannot conduct performance tests during SSM. Not a violation to exceed standard during SSM	Yes.
§63.7(e)(2)	Conditions for Conducting Performance Tests	Must conduct according to rule and EPA test methods unless Administrator approves alternative	Yes.
§63.7(e)(3)	Test Run Duration	Must have three test runs of at least one hour each. Compliance is based on arithmetic mean of three runs. Conditions when data from an additional test run can be used	Yes.
§63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an alternative test method	Yes.
§63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report. Must submit performance test data 60 days after end of test with the Notification of Compliance Status. Keep data for 5 years	Yes.
§63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test	Yes.
§63.8(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard	Yes.
§63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of part 60 apply	Yes.
§63.8(a)(3)	[Reserved]		

§63.8(a)(4)	Monitoring with Flares	Unless your rule says otherwise, the requirements for flares in 63.11 apply	Yes.
§63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative	Yes.
§63.8(b)(2)–(3)	Multiple Effluents and Multiple Monitoring Systems	Specific requirements for installing monitoring systems. Must install on each effluent before it is combined and before it is released to the atmosphere unless Administrator approves otherwise. If more than one monitoring system on an emissions point, must report all monitoring system results, unless one monitoring system is a backup	Yes.
§63.8(c)(1)	Monitoring System Operation and Maintenance	Maintain monitoring system in a manner consistent with good air pollution control practices	Yes.
§63.8(c)(1)(i)	Routine and Predictable SSM	Keep parts for routine repairs available; reporting requirements for SSM when action is described in SSM plan	Yes.
§63.8(c)(1)(ii)	SSM not in SSMP	Reporting requirements for SSM when action is not described in SSM plan	Yes.
§63.8(c)(1)(iii)	Compliance with Operation and Maintenance (O&M) Requirements	How Administrator determines if source complying with operation and maintenance requirements. Review of source O&M procedures, records, Manufacturer's instructions, recommendations, and inspection of monitoring system	Yes.
§63.8(c)(2)–(3)	Monitoring System Installation	Must install to get representative emissions and parameter measurements. Must verify operational status before or at performance test	Yes.
§63.8(c)(4)	Continuous Monitoring System (CMS) Requirements	CMS must be operating except during breakdown, out-of-control, repair, maintenance, and high-level calibration drifts	No.
§63.8(c)(4)(i)–(ii)	Continuous Monitoring System (CMS) Requirements	COMS must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period. CEMS must have a minimum of one cycle of operation for each successive 15-minute period	Yes. However, COMS are not applicable. Requirements for CPMS are listed in §§63.7900 and 63.7913.
§63.8(c)(5)	COMS Minimum Procedures	COMS minimum procedures	No.
§63.8(c)(6)	CMS Requirements	Zero and High level calibration check requirements	Yes. However requirements for CPMS are addressed in

			§63.7927.
§63.8(c)(7)–(8)	CMS Requirements	Out-of-control periods, including reporting	Yes.
§63.8(d)	CMS Quality Control	Requirements for CMS quality control, including calibration, etc. Must keep quality control plan on record for 5 years. Keep old versions for 5 years after revisions	Yes.
§63.8(e)	CMS Performance Evaluation	Notification, performance evaluation test plan, reports	Yes.
§63.8(f)(1)–(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring	Yes.
§63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for CEMS	No.
§63.8(g)(1)–(4)	Data Reduction	COMS 6-minute averages calculated over at least 36 evenly spaced data points. CEMS 1-hour averages computed over at least four equally spaced data points	Yes. However, COMS are not applicable. Requirements for CPMS are addressed in §§63.7900 and 63.7913.
§63.8(g)(5)	Data Reduction	Data that cannot be used in computing averages for CEMS and COMS	No.
§63.9(a)	Notification Requirements	Applicability and State Delegation	Yes.
§63.9(b)(1)–(5)	Initial Notifications.	Submit notification 120 days after effective date. Notification of intent to construct/reconstruct; Notification of commencement of construct/reconstruct; Notification of startup. Contents of each	Yes.
§63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed BACT/LAER	Yes.
§63.9(d)	Notification of Special Compliance Requirements for New Source	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date	Yes.
§63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	Yes.
§63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.
§63.9(g)	Additional Notifications When Using CMS	Notification of performance evaluation. Notification using COMS data. Notification that exceeded criterion for relative accuracy	Yes. However, there are no opacity standards.
§63.9(h)(1)–(6)	Notification of Compliance Status	Contents. Due 60 days after end of performance test or other compliance demonstration, except for opacity/VE, which are due 30 days after. When to submit to Federal vs. State authority	Yes.

§63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change in when notifications must be submitted	Yes.
§63.9(j)	Change in Previous Information	Must submit within 15 days after the change	Yes.
§63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension. When to submit to Federal vs. State authority. Procedures for owners of more than 1 source	Yes.
§63.10(b)(1)	Recordkeeping/Reporting	General Requirements. Keep all records readily available. Keep for 5 years	Yes.
§63.10(b)(2)(i)–(iv)	Records related to SSM	Occurrence of each of operation (process equipment). Occurrence of each malfunction of air pollution equipment. Maintenance on air pollution control equipment. Actions during startup, shutdown, and malfunction	Yes.
§63.10(b)(2)(vi) and (x–xi)	CMS Records	Malfunctions, inoperative, out-of-control. Calibration checks. Adjustments, maintenance	Yes.
§63.10(b)(2)(vii)–(ix)	Records	Measurements to demonstrate compliance with emissions limitations. Performance test, performance evaluation, and visible emissions observation results. Measurements to determine conditions of performance tests and performance evaluations	Yes.
§63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test	No.
§63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status	Yes.
§63.10(b)(3)	Records	Applicability Determinations	Yes.
§63.10(c)	Records	Additional Records for CMS	No.
§63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§63.10(d)(2)	Report of Performance Test Results	When to submit to Federal or State authority	Yes.
§63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	No.
§63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension	Yes.
§63.10(d)(5)	Startup, Shutdown, and Malfunction Reports	Contents and submission	Yes.
§63.10(e)(1)–(2)	Additional CMS Reports	Must report results for each CEM on a unit	Yes. However,

		Written copy of performance evaluation Three copies of COMS performance evaluation	COMS are not applicable.
§63.10(e)(3)	Reports	Excess Emissions Reports	No.
§63.10(e)(3)(i–iii)	Reports	Schedule for reporting excess emissions and parameter monitor exceedance (now defined as deviations)	No.
§63.10(e)(3)(iv–v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedance (now defined as deviations). Provision to request semiannual reporting after compliance for one year. Submit report by 30th day following end of quarter or calendar half. If there has not been an exceedance or excess emissions (now defined as deviations), report contents is a statement that there have been no deviations	No.
§63.10(e)(3)(iv–v)	Excess Emissions Reports	Must submit report containing all of the information in §§63.10(c)(5–13) and 63.8(c)(7–8)	No.
§63.10(e)(3)(vi–viii)	Excess Emissions Report and Summary Report	Requirements for reporting excess emissions for CMSs (now called deviations). Requires all of the information in §§63.10(c)(5–13) and 63.8(c)(7–8)	No.
§63.10(e)(4)	Reporting COMS data	Must submit COMS data with performance test data	No.
§63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.
§63.11	Flares	Requirements for flares	Yes.
§63.12	Delegation	State authority to enforce standards	Yes.
§63.13	Addresses	Addresses where reports, notifications, and requests are sent	Yes.
§63.14	Incorporation by Reference	Test methods incorporated by reference	Yes.
§63.15	Availability of Information	Public and confidential information	Yes

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 20468, Apr. 20, 2006]

Section E.22 40 CFR 60, Subpart Db—New Source Performance Standards - Industrial-Commercial-Institutional Steam Generating Units

E.22.1 NSPS Subpart Db Requirements [40 CFR Part 60, Subpart Db] [326 IAC 12]

Pursuant to 40 CFR 60.40b, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart Db for New Boiler 1 and New Boiler 2 as specified below:

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b)

(c) Affected facilities that also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the PM and NOXstandards under this subpart and the SO2standards under subpart J (§60.104).

(d)

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).
(2) Section 60.44b(g).
(3) Section 60.49b(a)(4).

(h)

(i)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

(k)

§ 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration , also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.
Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO2control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State

Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is present as a gas at ISO conditions.

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m3 (70,000 Btu/hr-ft3).
ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m3 (70,000 Btu/hr-ft3) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical SO2emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO2emission control, has a SO2emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005, very low sulfur oil means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without SO2emission control, has a SO2emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

§ 60.44b Standard for nitrogen oxides (NOX).

(a)

(b)

(c)

(d)

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NOXin excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:
En= NOXemission limit (expressed as NO2), ng/J (lb/MMBtu);
ELgo= Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);
Hgo= Heat input from combustion of natural gas, distillate oil and gaseous byproduct/waste, J (MMBtu);
ELro= Appropriate emission limit from paragraph (a)(2) for combustion of residual oil and/or byproduct/waste, ng/J (lb/MMBtu);
Hro= Heat input from combustion of residual oil, J (MMBtu);
ELc= Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and
Hc= Heat input from combustion of coal, J (MMBtu).

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NOXemission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NOXemissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NOXemission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in §60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NOXemission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NOXemission limit will be established at the NOXemission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NOXemissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NOXlimit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g)

(h) For purposes of paragraph (i) of this section, the NOXstandards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j)

(k)

(l) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOX(expressed as NO2) in excess of the following limits:
(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: A limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or
(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:
En= NOXemission limit, (lb/MMBtu);
Hgo= 30-day heat input from combustion of natural gas or distillate oil; and
Hr= 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i) of subpart Da of this part, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NOXemission standards under §60.44b apply at all times.

(b)

(c) Compliance with the NOXemission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d)

(e) To determine compliance with the emission limits for NOXrequired under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NOXunder §60.48(b).

(1) For the initial compliance test, NOXfrom the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NOXemission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2)

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NOXstandards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NOXemission data for the preceding 30 steam generating unit operating days.

(4)

(5)

(f)

(g)

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NOXemission standards under §60.44b using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NOXemission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods.

(i)

(j)

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a)

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NOXstandard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NOXand O2(or CO2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NOXemission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.
(d) The 1-hour average NOXemission rates measured by the continuous NOXmonitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1)

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NOXis determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NOXspan values shall be determined as follows:

Fuel	Span values for NO_X (ppm)
Natural gas	500.
Oil	500.
Coal	1,000.
Mixtures	500 (x + y) + 1,000z.

Where:
x = Fraction of total heat input derived from natural gas;
y = Fraction of total heat input derived from oil; and
z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NOXspan values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NOXemission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g)

(h)

(i)

(j)

(k)

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4)

(b) The owner or operator of each affected facility subject to the SO2, PM, and/or NOXemission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NOXstandard of §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under §60.48b(g)(2) and the records to be maintained under §60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NOXemission rates (i.e. , ng/J or lbs/MMBtu heat input). Steam generating unit operating

conditions include, but are not limited to, the degree of staged combustion (i.e. , the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e. , flue gas O2level);

(2) Include the data and information that the owner or operator used to identify the relationship between NOXemission rates and these operating conditions; and
(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(j).

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(e)

(f)

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NOXstandards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NOXemission rates (expressed as NO2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NOXemission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NOXemission rates are in excess of the NOXemissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards under §60.43b(e) or to the operating parameter monitoring requirements under §60.13(i)(1).

(2) Any affected facility that is subject to the NOXstandard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NOXemissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NOXemission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NOXunder §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j)

(k)

(l)

(m)

(n)

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p)

(q)

(r)

(s)

(t)

(u)

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO2and/or NOXand/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating

whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x)

(y)

Section E.23 40 CFR 60, Subpart IIII— Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

E.23.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, except as otherwise specified in 40 CFR Part 60, Subpart IIII.

E.23.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60, Subpart IIII] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart IIII, the Permittee shall comply with the provisions of Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, which are incorporated by reference as 326 IAC 12, as specified as follows:

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are:

(i) Manufactured after April 1, 2006 and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(d)

(e)

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements
§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

(e) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

Notification, Reports, and Records for Owners and Operators
§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Special Requirements

40 CFR 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

(a) Owners and operators of stationary CI ICE that do not use diesel fuel, or who have been given authority by the Administrator under §60.4207(d) of this subpart to use fuels that do not meet the fuel requirements of paragraphs (a) and (b) of §60.4207, may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4202 or §60.4203 using such fuels.

(b) [Reserved]

General Provisions
§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means either:

(1) The calendar year in which the engine was originally produced, or

(2) The annual new model production period of the engine manufacturer if it is different than the calendar year. This must include January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year. For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was originally produced.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

Useful life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for useful life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for useful life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Tables to Subpart IIII of Part 60

Table 1 to Subpart IIII of Part 60.—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007–2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 3 to Subpart IIII of Part 60.—Certification Requirements for Stationary Fire Pump Engines

[As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:]

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)
130≤KW≤560 (175≤HP≤750)	2009

Table 4 to Subpart IIII of Part 60.—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)

[1]For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2]For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3]In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60.—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
KW≥130 (HP≥175)	2011

Table 8 to Subpart IIII of Part 60.—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Section E.24 40 CFR 63, Subpart EEEE— National Emission Standards for Hazardous Air Pollutants - Organic Liquid Distribution (Non-gasoline)

E.24.1 General Provisions Relating to NESHAP Subpart EEEE [326 IAC 20-83-1] [40 CFR Part 63, Subpart EEEE]

Pursuant to 40 CFR 63.2330 the Permittee shall comply with the provisions of 40 CFR Part 63 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, except as otherwise specified in 40 CFR Part 63, Subpart EEEE.

E.24.2 NESHAP Subpart EEEE Requirements [40 CFR 63, Subpart EEEE] [326 IAC 20-83-1]

Pursuant to 40 CFR 63.2330, the Permittee shall comply with the provisions of 40 CFR 63, Subpart EEEE, which are incorporated by refernce in 326 IAC 20-83-1, for the storage tank D-424 and other affected emissions units at this source, specified as follows:

What This Subpart Covers
§ 63.2330 What is the purpose of this subpart?

This subpart establishes national emission limitations, operating limits, and work practice standards for organic hazardous air pollutants (HAP) emitted from organic liquids distribution (OLD) (non-gasoline) operations at major sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations, operating limits, and work practice standards.

§ 63.2334 Am I subject to this subpart?

(a) Except as provided for in paragraphs (b) and (c) of this section, you are subject to this subpart if you own or operate an OLD operation that is located at, or is part of, a major source of HAP emissions. An OLD operation may occupy an entire plant site or be collocated with other industrial (*e.g.,* manufacturing) operations at the same plant site.

(b) Organic liquid distribution operations located at research and development facilities, consistent with section 112(c)(7) of the Clean Air Act (CAA), are not subject to this subpart.

(c)

§ 63.2338 What parts of my plant does this subpart cover?

(a) This subpart applies to each new, reconstructed, or existing OLD operation affected source.

(b) Except as provided in paragraph (c) of this section, the affected source is the collection of activities and equipment used to distribute organic liquids into, out of, or within a facility that is a major source of HAP. The affected source is composed of:

(1) All storage tanks storing organic liquids.

(2) All transfer racks at which organic liquids are loaded into or unloaded out of transport vehicles and/or containers.

(3) All equipment leak components in organic liquids service that are associated with:

(i) Storage tanks storing organic liquids;

(ii) Transfer racks loading or unloading organic liquids;

(iii) Pipelines that transfer organic liquids directly between two storage tanks that are subject to this subpart;

(iv) Pipelines that transfer organic liquids directly between a storage tank subject to this subpart and a transfer rack subject to this subpart; and

(v) Pipelines that transfer organic liquids directly between two transfer racks that are subject to this subpart.

(4) All transport vehicles while they are loading or unloading organic liquids at transfer racks subject to this subpart.

(5) All containers while they are loading or unloading organic liquids at transfer racks subject to this subpart.

(c) The equipment listed in paragraphs (c)(1) through (4) of this section and used in the identified operations is excluded from the affected source.

(1) Storage tanks, transfer racks, transport vehicles, containers, and equipment leak components that are part of an affected source under another 40 CFR part 63 national emission standards for hazardous air pollutants (NESHAP).

(2) Non-permanent storage tanks, transfer racks, transport vehicles, containers, and equipment leak components when used in special situation distribution loading and unloading operations (such as maintenance or upset liquids management).

(3) Storage tanks, transfer racks, transport vehicles, containers, and equipment leak components when used to conduct maintenance activities, such as stormwater management, liquid removal from tanks for inspections and maintenance, or changeovers to a different liquid stored in a storage tank.

(d) An affected source is a new affected source if you commenced construction of the affected source after April 2, 2002, and you meet the applicability criteria in §63.2334 at the time you commenced operation.

(e) An affected source is reconstructed if you meet the criteria for reconstruction as defined in §63.2.

(f) An affected source is existing if it is not new or reconstructed.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42904, July 28, 2006]

§ 63.2342 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to the schedule identified in paragraph (a)(1), (a)(2), or (a)(3) of this section, as applicable.

(1)

(2) If you commence construction of or reconstruct your affected source after February 3, 2004, you must comply with the emission limitations, operating limits, and work practice standards for new and reconstructed sources in this subpart upon startup of your affected source.

(3) If, after startup of a new affected source, the total actual annual facility-level organic liquid loading volume at that source exceeds the criteria for control in Table 2 to this subpart, items 9 and 10, the owner or operator must comply with the transfer rack requirements specified in §63.2346(b) immediately; that is, be in compliance the first day of the period following the end of the 3-year period triggering the control criteria.

(b)(1) If you have an existing affected source, you must comply with the emission limitations, operating limits, and work practice standards for existing affected sources no later than February 5, 2007, except as provided in paragraphs (b)(2) and (3) of this section.

(2) Floating roof storage tanks at existing affected sources must be in compliance with the work practice standards in Table 4 to this subpart, item 1, at all times after the next degassing and cleaning activity or within 10 years after February 3, 2004, whichever occurs first. If the first degassing and cleaning activity occurs during the 3 years following February 3, 2004, the compliance date is February 5, 2007.

(3)(i) If an addition or change other than reconstruction as defined in §63.2 is made to an existing affected facility that causes the total actual annual facility-level organic liquid loading volume to exceed the criteria for control in Table 2 to this subpart, items 7 and 8, the owner or operator must comply with the transfer rack requirements specified in §63.2346(b) immediately; that is, be in compliance the first day of the period following the end of the 3-year period triggering the control criteria.

(ii) If the owner or operator believes that compliance with the transfer rack emission limits cannot be achieved immediately, as specified in paragraph (b)(3)(i) of this section, the owner or operator may submit a request for a compliance extension, as specified in paragraphs (b)(3)(ii)(A) through (I) of this section. Subject to paragraph (b)(3)(ii)(B) of this section, until an extension of compliance has been granted by the Administrator (or a State with an approved permit program) under this paragraph (b)(3)(ii), the owner or operator of the transfer rack subject to the requirements of this section shall comply with all applicable requirements of this subpart. Advice on requesting an extension of compliance may be obtained from the Administrator (or the State with an approved permit program).

(A) *Submittal.* The owner or operator shall submit a request for a compliance extension to the Administrator (or a State, when the State has an approved 40 CFR part 70 permit program and the source is required to obtain a 40 CFR part 70 permit under that program, or a State, when the State has been delegated the authority to implement and enforce the emission standard for that source) seeking an extension allowing the source up to 1 additional year to comply with the transfer rack standard, if such additional period is necessary for the installation of controls. The owner or operator of the affected source who has requested an extension of compliance under this paragraph (b)(3)(ii)(A) and who is otherwise required to obtain a title V permit shall apply for such permit, or apply to have the source's title V permit revised to incorporate the conditions of the extension of compliance. The conditions of an extension of compliance granted under this paragraph (b)(3)(ii)(A) will be incorporated into the affected source's title V permit according to the provisions of 40 CFR part 70 or Federal title V regulations in this chapter (42 U.S.C. 7661), whichever are applicable.

(B) *When to submit.* (*1*) Any request submitted under paragraph (b)(3)(ii)(A) of this section must be submitted in writing to the appropriate authority no later than 120 days prior to the affected source's compliance date (as specified in paragraph (b)(3)(i) of this section), except as provided for in paragraph (b)(3)(ii)(B)(*2*) of this section. Nonfrivolous requests submitted under this paragraph (b)(3)(ii)(B)(*1*) will stay the applicability of the rule as to the emission points in question until such time as the request is granted or denied. A denial will be effective as of the date of denial.

(*2*) An owner or operator may submit a compliance extension request after the date specified in paragraph (b)(3)(ii)(B)(*1*) of this section provided the need for the compliance extension arose after that date, and before the otherwise applicable compliance date and the need arose due to circumstances beyond reasonable control of the owner or operator. This request must include, in addition to the information required in paragraph (b)(3)(ii)(C) of this section, a statement of the reasons additional time is needed and the date when the owner or operator first learned of the problems. Nonfrivolous requests submitted under this paragraph (b)(3)(ii)(B)(*2*) will stay the applicability of the rule as to the emission points in question until such time as the request is granted or denied. A denial will be effective as of the original compliance date.

(C) *Information required.* The request for a compliance extension under paragraph (b)(3)(ii)(A) of this section shall include the following information:

(*1*) The name and address of the owner or operator and the address of the existing source if it differs from the address of the owner or operator;

(*2*) The name, address, and telephone number of a contact person for further information;

(*3*) An identification of the organic liquid distribution operation and of the specific equipment for which additional compliance time is required;

(*4*) A description of the controls to be installed to comply with the standard;

(*5*) Justification for the length of time being requested; and

(*6*) A compliance schedule, including the date by which each step toward compliance will be reached. At a minimum, the list of dates shall include:

(*i*) The date by which on-site construction, installation of emission control equipment, or a process change is planned to be initiated;

(*ii*) The date by which on-site construction, installation of emission control equipment, or a process change is to be completed; and

(*iii*) The date by which final compliance is to be achieved.

(D) *Approval of request for extension of compliance.* Based on the information provided in any request made under paragraph (b)(3)(ii)(C) of this section, or other information, the Administrator (or the State with an approved permit program) may grant an extension of compliance with the transfer rack emission standard, as specified in paragraph (b)(3)(ii) of this section. The extension will be in writing and will—

(*1*) Identify each affected source covered by the extension;

(*2*) Specify the termination date of the extension;

(*3*) Specify the dates by which steps toward compliance are to be taken, if appropriate;

(*4*) Specify other applicable requirements to which the compliance extension applies (e.g., performance tests);

(*5*) Specify the contents of the progress reports to be submitted and the dates by which such reports are to be submitted, if required pursuant to paragraph (b)(3)(ii)(E) of this section.

(*6*) Under paragraph (b)(3)(ii) of this section, specify any additional conditions that the Administrator (or the State) deems necessary to assure installation of the necessary controls and protection of the health of persons during the extension period.

(E) *Progress reports.* The owner or operator of an existing source that has been granted an extension of compliance under paragraph (b)(3)(ii)(D) of this section may be required to submit to the Administrator (or the State with an approved permit program) progress reports indicating whether the steps toward compliance outlined in the compliance schedule have been reached.

(F) *Notification of approval or intention to deny.* (*1*) The Administrator (or the State with an approved permit program) will notify the owner or operator in writing of approval or intention to deny approval of a request for an extension of compliance within 30 calendar days after receipt of sufficient information to evaluate a request submitted under paragraph (b)(3)(ii) of this section. The Administrator (or the State) will notify the owner or operator in writing of the status of his/her application; that is, whether the application contains sufficient information to make a determination, within 30 calendar days after receipt of the original application and within 30 calendar days after receipt of any supplementary information that is submitted. The 30-day approval or denial period will begin after the owner or operator has been notified in writing that his/her application is complete. Failure by the Administrator to act within 30 calendar days to approve or disapprove a request submitted under paragraph (b)(3)(ii) of this section does not constitute automatic approval of the request.

(*2*) When notifying the owner or operator that his/her application is not complete, the Administrator will specify the information needed to complete the application and provide notice of opportunity for the applicant to present, in writing, within 30 calendar days after he/she is notified of the incomplete application, additional information or arguments to the Administrator to enable further action on the application.

(*3*) Before denying any request for an extension of compliance, the Administrator (or the State with an approved permit program) will notify the owner or operator in writing of the Administrator's (or the State's) intention to issue the denial, together with:

(*i*) Notice of the information and findings on which the intended denial is based; and

(*ii*) Notice of opportunity for the owner or operator to present in writing, within 15 calendar days after he/she is notified of the intended denial, additional information or arguments to the Administrator (or the State) before further action on the request.

(*4*) The Administrator's final determination to deny any request for an extension will be in writing and will set forth the specific grounds on which the denial is based. The final determination will be made within 30 calendar days after presentation of additional information or argument (if the application is complete), or within 30 calendar days after the final date specified for the presentation if no presentation is made.

(G) *Termination of extension of compliance.* The Administrator (or the State with an approved permit program) may terminate an extension of compliance at an earlier date than specified if any specification under paragraph (b)(3)(ii)(D)(*3*) or paragraph (b)(3)(ii)(D)(*4*) of this section is not met. Upon a determination to terminate, the Administrator will notify, in writing, the owner or operator of the Administrator's determination to terminate, together with:

(*1*) Notice of the reason for termination; and

(*2*) Notice of opportunity for the owner or operator to present in writing, within 15 calendar days after he/she is notified of the determination to terminate, additional information or arguments to the Administrator before further action on the termination.

(*3*) A final determination to terminate an extension of compliance will be in writing and will set forth the specific grounds on which the termination is based. The final determination will be made within 30 calendar days after presentation of additional information or arguments, or within 30 calendar days after the final date specified for the presentation if no presentation is made.

(H) The granting of an extension under this section shall not abrogate the Administrator's authority under section 114 of the CAA.

(I) *Limitation on use of compliance extension.* The owner or operator may request an extension of compliance under the provisions specified in paragraph (b)(3)(ii) of this section only once for each facility.

(c)

(d) You must meet the notification requirements in §§63.2343 and 63.2382(a), as applicable, according to the schedules in §63.2382(a) and (b)(1) through (3) and in subpart A of this part. Some of these notifications must be submitted before the compliance dates for the emission limitations, operating limits, and work practice standards in this subpart.

Testing and Initial Compliance Requirements
§ 63.2354 What performance tests, design evaluations, and performance evaluations must I conduct?

(a)(1) For each performance test that you conduct, you must use the procedures specified in subpart SS of this part and the provisions specified in paragraph (b) of this section.

(2) For each design evaluation you conduct, you must use the procedures specified in subpart SS of this part.

(3) For each performance evaluation of a continuous emission monitoring system (CEMS) you conduct, you must follow the requirements in §63.8(e).

(b)(1) For nonflare control devices, you must conduct each performance test according to the requirements in §63.7(e)(1), and either §63.988(b), §63.990(b), or §63.995(b), using the procedures specified in §63.997(e).

(2) You must conduct three separate test runs for each performance test on a nonflare control device as specified in §§63.7(e)(3) and 63.997(e)(1)(v). Each test run must last at least 1 hour, except as provided in §63.997(e)(1)(v)(A) and (B).

(3)(i) In addition to EPA Method 25 or 25A of 40 CFR part 60, appendix A, to determine compliance with the organic HAP or TOC emission limit, you may use EPA Method 18 of 40 CFR part 60, appendix A, as specified in paragraph (b)(3)(i) of this section. As an alternative to EPA Method 18, you may use ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference, see §63.14), under the conditions specified in paragraph (b)(3)(ii) of this section.

(A) If you use EPA Method 18 to measure compliance with the percentage efficiency limit, you must first determine which organic HAP are present in the inlet gas stream (i.e., uncontrolled emissions) using knowledge of the organic liquids or the screening procedure described in EPA Method 18. In conducting the performance test, you must analyze samples collected as specified in EPA Method 18, simultaneously at the inlet and outlet of the control device. Quantify the emissions for the same organic HAP identified as present in the inlet gas stream for both the inlet and outlet gas streams of the control device.

(B) If you use EPA Method 18 of 40 CFR part 60, appendix A, to measure compliance with the emission concentration limit, you must first determine which organic HAP are present in the inlet gas stream using knowledge of the organic liquids or the screening procedure described in EPA Method 18. In conducting the performance test, analyze samples collected as specified in EPA Method 18 at the outlet of the control device. Quantify the control device outlet emission concentration for the same organic HAP identified as present in the inlet or uncontrolled gas stream.

(ii) You may use ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference, see §63.14), as an alternative to EPA Method 18 if the target concentration is between 150 parts per billion by volume and 100 ppmv and either of the conditions specified in paragraph (b)(2)(ii)(A) or (B) of this section exists. For target compounds not listed in Section 1.1 of ASTM D6420–99 (Reapproved 2004) and not amenable to detection by mass spectrometry, you may not use ASTM D6420–99 (Reapproved 2004).

(A) The target compounds are those listed in Section 1.1 of ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference, see §63.14),; or

(B) For target compounds not listed in Section 1.1 of ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference, see §63.14), but potentially detected by mass spectrometry, the additional system continuing calibration check after each run, as detailed in ASTM D6420–99 (Reapproved 2004), Section 10.5.3, must be followed, met, documented, and submitted with the data report, even if there is no moisture condenser used or the compound is not considered water-soluble.

(4) If a principal component of the uncontrolled or inlet gas stream to the control device is formaldehyde, you may use EPA Method 316 of appendix A of this part instead of EPA Method 18 of 40 CFR part 60, appendix A, for measuring the formaldehyde. If formaldehyde is the predominant organic HAP in the inlet gas stream, you may use EPA Method 316 alone to measure formaldehyde either at the inlet and outlet of the control device using the formaldehyde control efficiency as a surrogate for total organic HAP or TOC efficiency, or at the outlet of a combustion device for determining compliance with the emission concentration limit.

(5) You may not conduct performance tests during periods of SSM, as specified in §63.7(e)(1).

(c) To determine the HAP content of the organic liquid, you may use EPA Method 311 of 40 CFR part 63, appendix A, or other method approved by the Administrator. In addition, you may use other means, such as voluntary consensus standards, material safety data sheets (MSDS), or certified product data sheets, to determine the HAP content of the organic liquid. If the method you select to determine the HAP content provides HAP content ranges, you must use the upper end of each HAP content range in determining the total HAP content of the organic liquid. The EPA may require you to test the HAP content of an organic liquid using EPA Method 311 or other method approved by the Administrator. If the results of the EPA Method 311 (or any other approved method) are different from the HAP content determined by another means, the EPA Method 311 (or approved method) results will govern.

Notifications, Reports, and Records
§ 63.2382 What notifications must I submit and when and what information should be submitted?

(a) You must submit each notification in subpart SS of this part, Table 12 to this subpart, and paragraphs (b) through (d) of this section that applies to you. You must submit these notifications according to the schedule in Table 12 to this subpart and as specified in paragraphs (b) through (d) of this section.

(b)(1) *Initial Notification.* If you startup your affected source before February 3, 2004, you must submit the Initial Notification no later than 120 calendar days after February 3, 2004.

(2) If you startup your new or reconstructed affected source on or after February 3, 2004, you must submit the Initial Notification no later than 120 days after initial startup.

(c) If you are required to conduct a performance test, you must submit the Notification of Intent to conduct the test at least 60 calendar days before it is initially scheduled to begin as required in §63.7(b)(1).

(d)(1) *Notification of Compliance Status.* If you are required to conduct a performance test, design evaluation, or other initial compliance demonstration as specified in Table 5, 6, or 7 to this subpart, you must submit a Notification of Compliance Status.

(2) The Notification of Compliance Status must include the information required in §63.999(b) and in paragraphs (d)(2)(i) through (viii) of this section.

(i) The results of any applicability determinations, emission calculations, or analyses used to identify and quantify organic HAP emissions from the affected source.

(ii) The results of emissions profiles, performance tests, engineering analyses, design evaluations, flare compliance assessments, inspections and repairs, and calculations used to demonstrate initial compliance according to Tables 6 and 7 to this subpart. For performance tests, results must include descriptions of sampling and analysis procedures and quality assurance procedures.

(iii) Descriptions of monitoring devices, monitoring frequencies, and the operating limits established during the initial compliance demonstrations, including data and calculations to support the levels you establish.

(iv) Descriptions of worst-case operating and/or testing conditions for the control device(s).

(v) Identification of emission sources subject to overlapping requirements described in §63.2396 and the authority under which you will comply.

(vi) The applicable information specified in §63.1039(a)(1) through (3) for all pumps and valves subject to the work practice standards for equipment leak components in Table 4 to this subpart, item 4.

(vii) If you are complying with the vapor balancing work practice standard for transfer racks according to Table 4 to this subpart, item 3.a, include a statement to that effect and a statement that the pressure vent settings on the affected storage tanks are greater than or equal to 2.5 psig.

(viii) The information specified in §63.2386(c)(10)(i), unless the information has already been submitted with the first Compliance report. If the information specified in §63.2386(c)(10)(i) has already been

submitted with the first Compliance report, the information specified in §63.2386(d)(3) and (4), as applicable, shall be submitted instead.

What reports must I submit and when and what information is to be submitted in each?

(a) You must submit each report in subpart SS of this part, Table 11 to this subpart, Table 12 to this subpart, and in paragraphs (c) through (e) of this section that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report according to Table 11 to this subpart and by the dates shown in paragraphs (b)(1) through (3) of this section, by the dates shown in subpart SS of this part, and by the dates shown in Table 12 to this subpart, whichever are applicable.

(1)(i) The first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.2342 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your affected source in §63.2342.

(ii) The first Compliance report must be postmarked no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.2342.

(2)(i) Each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(ii) Each subsequent Compliance report must be postmarked no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(3) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) and (2) of this section.

(c) *First Compliance report.* The first Compliance report must contain the information specified in paragraphs (c)(1) through (10) of this section.

(1) Company name and address.

(2) Statement by a responsible official, including the official's name, title, and signature, certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

(3) Date of report and beginning and ending dates of the reporting period.

(4) Any changes to the information listed in §63.2382(d)(2) that have occurred since the submittal of the Notification of Compliance Status.

(5) If you had a SSM during the reporting period and you took actions consistent with your SSM plan, the Compliance report must include the information described in §63.10(d)(5)(i).

(6) If there are no deviations from any emission limitation or operating limit that applies to you and there are no deviations from the requirements for work practice standards, a statement that there were no deviations from the emission limitations, operating limits, or work practice standards during the reporting period.

(7) If there were no periods during which the CMS was out of control as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out of control during the reporting period.

(8) For closed vent systems and control devices used to control emissions, the information specified in paragraphs (c)(8)(i) and (ii) of this section for those planned routine maintenance activities that would require the control device to not meet the applicable emission limit.

(i) A description of the planned routine maintenance that is anticipated to be performed for the control device during the next 6 months. This description must include the type of maintenance necessary, planned frequency of maintenance, and lengths of maintenance periods.

(ii) A description of the planned routine maintenance that was performed for the control device during the previous 6 months. This description must include the type of maintenance performed and the total number of hours during those 6 months that the control device did not meet the applicable emission limit due to planned routine maintenance.

(9) A listing of all transport vehicles into which organic liquids were loaded at transfer racks that are subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10, during the previous 6 months for which vapor tightness documentation as required in §63.2390(c) was not on file at the facility.

(10)(i) A listing of all transfer racks (except those racks at which only unloading of organic liquids occurs) and of tanks greater than or equal to 18.9 cubic meters (5,000 gallons) that are part of the affected source but are not subject to any of the emission limitations, operating limits, or work practice standards of this subpart.

(ii) If the information specified in paragraph (c)(10)(i) of this section has already been submitted with the Notification of Compliance Status, the information specified in paragraphs (d)(3) and (4) of this section, as applicable, shall be submitted instead.

(d) *Subsequent Compliance reports* . Subsequent Compliance reports must contain the information in paragraphs (c)(1) through (9) of this section and, where applicable, the information in paragraphs (d)(1) through (4) of this section.

(1) For each deviation from an emission limitation occurring at an affected source where you are using a CMS to comply with an emission limitation in this subpart, you must include in the Compliance report the applicable information in paragraphs (d)(1)(i) through (xii) of this section. This includes periods of SSM.

(i) The date and time that each malfunction started and stopped.

(ii) The dates and times that each CMS was inoperative, except for zero (low-level) and high-level checks.

(iii) For each CMS that was out of control, the information in §63.8(c)(8).

(iv) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of SSM, or during another period.

(v) A summary of the total duration of the deviations during the reporting period, and the total duration as a percentage of the total emission source operating time during that reporting period.

(vi) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(vii) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percentage of the total emission source operating time during that reporting period.

(viii) An identification of each organic HAP that was potentially emitted during each deviation based on the known organic HAP contained in the liquid(s).

(ix) A brief description of the emission source(s) at which the CMS deviation(s) occurred.

(x) A brief description of each CMS that was out of control during the period.

(xi) The date of the latest certification or audit for each CMS.

(xii) A brief description of any changes in CMS, processes, or controls since the last reporting period.

(2) Include in the Compliance report the information in paragraphs (d)(2)(i) through (iii) of this section, as applicable.

(i) For each storage tank and transfer rack subject to control requirements, include periods of planned routine maintenance during which the control device did not comply with the applicable emission limits in table 2 to this subpart.

(ii) For each storage tank controlled with a floating roof, include a copy of the inspection record (required in §63.1065(b)) when inspection failures occur.

(iii) If you elect to use an extension for a floating roof inspection in accordance with §63.1063(c)(2)(iv)(B) or (e)(2), include the documentation required by those paragraphs.

(3)(i) A listing of any storage tank that became subject to controls based on the criteria for control specified in table 2 to this subpart, items 1 through 6, since the filing of the last Compliance report.

(ii) A listing of any transfer rack that became subject to controls based on the criteria for control specified in table 2 to this subpart, items 7 through 10, since the filing of the last Compliance report.

(4)(i) A listing of tanks greater than or equal to 18.9 cubic meters (5,000 gallons) that became part of the affected source but are not subject to any of the emission limitations, operating limits, or work practice standards of this subpart, since the last Compliance report.

(ii) A listing of all transfer racks (except those racks at which only the unloading of organic liquids occurs) that became part of the affected source but are not subject to any of the emission limitations, operating limits, or work practice standards of this subpart, since the last Compliance report.

(e) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to table 11 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission limitation in this subpart, we will consider submission of the Compliance report as satisfying any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report will not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the applicable title V permitting authority.

§ 63.2390 What records must I keep?

(a) For each emission source identified in §63.2338 that does not require control under this subpart, you must keep all records identified in §63.2343.

(b) For each emission source identified in §63.2338 that does require control under this subpart:

(1) You must keep all records identified in subpart SS of this part and in table 12 to this subpart that are applicable, including records related to notifications and reports, SSM, performance tests, CMS, and performance evaluation plans; and

(2) You must keep the records required to show continuous compliance, as required in subpart SS of this part and in tables 8 through 10 to this subpart, with each emission limitation, operating limit, and work practice standard that applies to you.

(c) For each transport vehicle into which organic liquids are loaded at a transfer rack that is subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10, you must keep the applicable records in paragraphs (c)(1) and (2) of this section or alternatively the verification records in paragraph (c)(3) of this section.

(1) For transport vehicles equipped with vapor collection equipment, the documentation described in 40 CFR 60.505(b), except that the test title is: Transport Vehicle Pressure Test-EPA Reference Method 27.

(2) For transport vehicles without vapor collection equipment, current certification in accordance with the U.S. DOT pressure test requirements in 49 CFR part 180 for cargo tanks or 49 CFR 173.31 for tank cars.

(3) In lieu of keeping the records specified in paragraph (c)(1) or (2) of this section, as applicable, the owner or operator shall record that the verification of U.S. DOT tank certification or Method 27 of appendix A to 40 CFR part 60 testing, required in table 5 to this subpart, item 2, has been performed. Various methods for the record of verification can be used, such as: A check-off on a log sheet, a list of U.S. DOT serial numbers or Method 27 data, or a position description for gate security showing that the security guard will not allow any trucks on site that do not have the appropriate documentation.

(d) You must keep records of the total actual annual facility-level organic liquid loading volume as defined in §63.2406 through transfer racks to document the applicability, or lack thereof, of the emission limitations in table 2 to this subpart, items 7 through 10.

(e) An owner or operator who elects to comply with §63.2346(a)(4) shall keep the records specified in paragraphs (e)(1) through (3) of this section.

(1) A record of the U.S. DOT certification required by §63.2346(a)(4)(ii).

(2) A record of the pressure relief vent setting specified in §63.2348(a)(4)(v).

(3) If complying with §63.2348(a)(4)(vi)(B), keep the records specified in paragraphs (e)(3)(i) and (ii) of this section.

(i) A record of the equipment to be used and the procedures to be followed when reloading the cargo tank or tank car and displacing vapors to the storage tank from which the liquid originates.

(ii) A record of each time the vapor balancing system is used to comply with §63.2348(a)(4)(vi)(B).

§ 63.2394 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious inspection and review according to §63.10(b)(1), including records stored in electronic form at a separate location.

(b) As specified in §63.10(b)(1), you must keep your files of all information (including all reports and notifications) for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You may keep the records off site for the remaining 3 years.

§ 63.2398 What parts of the General Provisions apply to me?

Table 12 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§ 63.2402 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. Environmental Protection Agency (U.S. EPA) or a delegated authority such as your State, local, or eligible tribal agency. If the EPA Administrator has delegated authority to your State, local, or eligible tribal agency, then that agency, as well as the EPA,

has the authority to implement and enforce this subpart. You should contact your EPA Regional Office (see list in §63.13) to find out if this subpart is delegated to your State, local, or eligible tribal agency.

(b) In delegating implementation and enforcement authority for this subpart to a State, local, or eligible tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not delegated to the State, local, or eligible tribal agency.

(1) Approval of alternatives to the nonopacity emission limitations, operating limits, and work practice standards in §63.2346(a) through (c) under §63.6(g).

(2) Approval of major changes to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major changes to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major changes to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

§ 63.2406 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in §63.2, 40 CFR part 63, subparts H, PP, SS, TT, UU, and WW, and in this section. If the same term is defined in another subpart and in this section, it will have the meaning given in this section for purposes of this subpart. Notwithstanding the introductory language in §63.921, the terms “container” and “safety device” shall have the meaning found in this subpart and not in §63.921.

Actual annual average temperature, for organic liquids, means the temperature determined using the following methods:

(1) For heated or cooled storage tanks, use the calculated annual average temperature of the stored organic liquid as determined from a design analysis of the storage tank.

(2) For ambient temperature storage tanks:

(i) Use the annual average of the local (nearest) normal daily mean temperatures reported by the National Climatic Data Center; or

(ii) Use any other method that the EPA approves.

Annual average true vapor pressure means the equilibrium partial pressure exerted by the total table 1 organic HAP in the stored or transferred organic liquid. For the purpose of determining if a liquid meets the definition of an organic liquid, the vapor pressure is determined using standard conditions of 77 degrees F and 29.92 inches of mercury. For the purpose of determining whether an organic liquid meets the applicability criteria in table 2, items 1 through 6, to this subpart, use the actual annual average temperature as defined in this subpart. The vapor pressure value in either of these cases is determined:

(1) In accordance with methods described in American Petroleum Institute Publication 2517, Evaporative Loss from External Floating-Roof Tanks (incorporated by reference, see §63.14);

(2) Using standard reference texts;

(3) By the American Society for Testing and Materials Method D2879–83, 96 (incorporated by reference, see §63.14); or

(4) Using any other method that the EPA approves.

Bottoms receiver means a tank that collects distillation bottoms before the stream is sent for storage or for further processing downstream.

Cargo tank means a liquid-carrying tank permanently attached and forming an integral part of a motor vehicle or truck trailer. This term also refers to the entire cargo tank motor vehicle or trailer. For the

purpose of this subpart, vacuum trucks used exclusively for maintenance or spill response are not considered cargo tanks.

Closed vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapors from an emission point to a control device. This system does not include the vapor collection system that is part of some transport vehicles or the loading arm or hose that is used for vapor return. For transfer racks, the closed vent system begins at, and includes, the first block valve on the downstream side of the loading arm or hose used to convey displaced vapors.

Combustion device means an individual unit of equipment, such as a flare, oxidizer, catalytic oxidizer, process heater, or boiler, used for the combustion of organic emissions.

Container means a portable unit in which a material can be stored, transported, treated, disposed of, or otherwise handled. Examples of containers include, but are not limited to, drums and portable cargo containers known as “portable tanks” or “totes.”

Control device means any combustion device, recovery device, recapture device, or any combination of these devices used to comply with this subpart. Such equipment or devices include, but are not limited to, absorbers, adsorbers, condensers, and combustion devices. Primary condensers, steam strippers, and fuel gas systems are not considered control devices.

Crude oil means any of the naturally occurring liquids commonly referred to as crude oil, regardless of specific physical properties. Only those crude oils downstream of the first point of custody transfer after the production field are considered crude oils in this subpart.

Custody transfer means the transfer of hydrocarbon liquids after processing and/or treatment in the producing operations, or from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

Design evaluation means a procedure for evaluating control devices that complies with the requirements in §63.985(b)(1)(i).

Deviation means any instance in which an affected source subject to this subpart, or portion thereof, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limitation (including any operating limit) or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart, and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation (including any operating limit) or work practice standard in this subpart during SSM.

Emission limitation means an emission limit, opacity limit, operating limit, or visible emission limit.

Equipment leak component means each pump, valve, and sampling connection system used in organic liquids service at an OLD operation. Valve types include control, globe, gate, plug, and ball. Relief and check valves are excluded.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals (4.0 pounds per square inch absolute (psia)) or greater which is used as a fuel for internal combustion engines. Aviation gasoline is included in this definition.

High throughput transfer rack means those transfer racks that transfer into transport vehicles (for existing affected sources) or into transport vehicles and containers (for new affected sources) a total of 11.8 million liters per year or greater of organic liquids.

In organic liquids service means that an equipment leak component contains or contacts organic liquids having 5 percent by weight or greater of the organic HAP listed in Table 1 to this subpart.

Low throughput transfer rack means those transfer racks that transfer into transport vehicles (for existing affected sources) or into transport vehicles and containers (for new affected sources) less than 11.8 million liters per year of organic liquids.

On-site or *on site* means, with respect to records required to be maintained by this subpart or required by another subpart referenced by this subpart, that records are stored at a location within a major source which encompasses the affected source. On-site includes, but is not limited to, storage at the affected source to which the records pertain, storage in central files elsewhere at the major source, or electronically available at the site.

Organic liquid means:

(1) Any non-crude oil liquid or liquid mixture that contains 5 percent by weight or greater of the organic HAP listed in Table 1 to this subpart, as determined using the procedures specified in §63.2354(c).

(2) Any crude oils downstream of the first point of custody transfer.

(3) Organic liquids for purposes of this subpart do not include the following liquids:

(i) Gasoline (including aviation gasoline), kerosene (No. 1 distillate oil), diesel (No. 2 distillate oil), asphalt, and heavier distillate oils and fuel oils;

(ii) Any fuel consumed or dispensed on the plant site directly to users (such as fuels for fleet refueling or for refueling marine vessels that support the operation of the plant);

(iii) Hazardous waste;

(iv) Wastewater;

(v) Ballast water: or

(vi) Any non-crude oil liquid with an annual average true vapor pressure less than 0.7 kilopascals (0.1 psia).

Organic liquids distribution (OLD) operation means the combination of activities and equipment used to store or transfer organic liquids into, out of, or within a plant site regardless of the specific activity being performed. Activities include, but are not limited to, storage, transfer, blending, compounding, and packaging.

Permitting authority means one of the following:

(1) The State Air Pollution Control Agency, local agency, or other agency authorized by the EPA Administrator to carry out a permit program under 40 CFR part 70; or

(2) The EPA Administrator, in the case of EPA-implemented permit programs under title V of the CAA (42 U.S.C. 7661) and 40 CFR part 71.

Plant site means all contiguous or adjoining surface property that is under common control, including surface properties that are separated only by a road or other public right-of-way. Common control includes surface properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination.

Research and development facility means laboratory and pilot plant operations whose primary purpose is to conduct research and development into new processes and products, where the operations are under the close supervision of technically trained personnel, and which are not engaged in the manufacture of products for commercial sale, except in a *de minimis* manner.

Responsible official means responsible official as defined in 40 CFR 70.2 and 40 CFR 71.2, as applicable.

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device that functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event.

Shutdown means the cessation of operation of an OLD affected source, or portion thereof (other than as part of normal operation of a batch-type operation), including equipment required or used to comply with this subpart, or the emptying and degassing of a storage tank. Shutdown as defined here includes, but is not limited to, events that result from periodic maintenance, replacement of equipment, or repair.

Startup means the setting in operation of an OLD affected source, or portion thereof (other than as part of normal operation of a batch-type operation), for any purpose. Startup also includes the placing in operation of any individual piece of equipment required or used to comply with this subpart including, but not limited to, control devices and monitors.

Storage tank means a stationary unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, or reinforced plastic) that provide structural support and is designed to hold a bulk quantity of liquid. Storage tanks do not include:

(1) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;

(2) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;

(3) Bottoms receivers;

(4) Surge control vessels;

(5) Vessels storing wastewater; or

(6) Reactor vessels associated with a manufacturing process unit.

Surge control vessel means feed drums, recycle drums, and intermediate vessels. Surge control vessels are used within chemical manufacturing processes when in-process storage, mixing, or management of flow rates or volumes is needed to assist in production of a product.

Tank car means a car designed to carry liquid freight by rail, and including a permanently attached tank.

Total actual annual facility-level organic liquid loading volume means the total facility-level actual volume of organic liquid loaded for transport within or out of the facility through transfer racks that are part of the affected source into transport vehicles (for existing affected sources) or into transport vehicles and containers (for new affected sources) based on a 3-year rolling average, calculated annually.

(1) For existing affected sources, each 3-year rolling average is based on actual facility-level loading volume during each calendar year (January 1 through December 31) in the 3-year period. For calendar year 2004 only (the first year of the initial 3-year rolling average), if an owner or operator of an affected source does not have actual loading volume data for the time period from January 1, 2004, through February 2, 2004 (the time period prior to the effective date of the OLD NESHAP), the owner or operator shall compute a facility-level loading volume for this time period as follows: At the end of the 2004 calendar year, the owner or operator shall calculate a daily average facility-level loading volume (based on the actual loading volume for February 3, 2004, through December 31, 2004) and use that daily average to estimate the facility-level loading volume for the period of time from January 1, 2004, through February 2, 2004. The owner or operator shall then sum the estimated facility-level loading volume from January 1, 2004, through February 2, 2004, and the actual facility-level loading volume from February 3, 2004, through December 31, 2004, to calculate the annual facility-level loading volume for calendar year 2004.

(2)(i) For new affected sources, the 3-year rolling average is calculated as an average of three 12-month periods. An owner or operator must select as the beginning calculation date with which to start the calculations as either the initial startup date of the new affected source or the first day of the calendar month following the month in which startup occurs. Once selected, the date with which the calculations begin cannot be changed.

(ii) The initial 3-year rolling average is based on the projected maximum facility-level annual loading volume for each of the 3 years following the selected beginning calculation date. The second 3-year rolling average is based on actual facility-level loading volume for the first year of operation plus a new projected maximum facility-level annual loading volume for second and third years following the selected beginning calculation date. The third 3-year rolling average is based on actual facility-level loading volume for the first 2 years of operation plus a new projected maximum annual facility-level loading volume for the third year following the beginning calculation date. Subsequent 3-year rolling averages are based on actual facility-level loading volume for each year in the 3-year rolling average.

Transfer rack means a single system used to load organic liquids into, or unload organic liquids out of, transport vehicles or containers. It includes all loading and unloading arms, pumps, meters, shutoff valves, pressure relief discharges, and other piping and equipment necessary for the transfer operation. Transfer equipment and operations that are physically separate (i.e., do not share common piping, valves, and other equipment) are considered to be separate transfer racks.

Transport vehicle means a cargo tank or tank car.

Vapor balancing system means:

(1) A piping system that collects organic HAP vapors displaced from transport vehicles or containers during loading and routes the collected vapors to the storage tank from which the liquid being loaded originated or to another storage tank connected to a common header. For containers, the piping system must route the displaced vapors directly to the appropriate storage tank or to another storage tank connected to a common header in order to qualify as a vapor balancing system; or

(2) A piping system that collects organic HAP vapors displaced from the loading of a storage tank and routes the collected vapors to the transport vehicle from which the storage tank is filled.

Vapor collection system means any equipment located at the source (i.e., at the OLD operation) that is not open to the atmosphere; that is composed of piping, connections, and, if necessary, flow-inducing devices; and that is used for:

(1) Containing and conveying vapors displaced during the loading of transport vehicles to a control device;

(2) Containing and directly conveying vapors displaced during the loading of containers; or

(3) Vapor balancing. This does not include any of the vapor collection equipment that is installed on the transport vehicle.

Vapor-tight transport vehicle means a transport vehicle that has been demonstrated to be vapor-tight. To be considered vapor-tight, a transport vehicle equipped with vapor collection equipment must undergo a pressure change of no more than 250 pascals (1 inch of water) within 5 minutes after it is pressurized to 4,500 pascals (18 inches of water). This capability must be demonstrated annually using the procedures specified in EPA Method 27 of 40 CFR part 60, appendix A. For all other transport vehicles, vapor tightness is demonstrated by performing the U.S. DOT pressure test procedures for tank cars and cargo tanks.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.

Table 1 to Subpart EEEE of Part 63—Organic Hazardous Air Pollutants

You must use the organic HAP information listed in the following table to determine which of the liquids handled at your facility meet the HAP content criteria in the definition of Organic Liquid in §63.2406.

Compound name	CAS No.[1]
2,4-D salts and esters	94–75–7
Acetaldehyde	75–07–0
Acetonitrile	75–05–8
Acetophenone	98–86–2
Acrolein	107–02–8
Acrylamide	79–06–1
Acrylic acid	79–10–7
Acrylonitrile	107–13–1
Allyl chloride	107–05–1
Aniline	62–53–3
Benzene	71–43–2
Biphenyl	92–52–4
Butadiene (1,3-)	106–99–0
Carbon tetrachloride	56–23–5
Chloroacetic acid	79–11–8
Chlorobenzene	108–90–7
2-Chloro-1,3-butadiene (Chloroprene)	126–99–8
Chloroform	67–66–3
m-Cresol	108–39–4
o-Cresol	95–48–7
p-Cresol	106–44–5
Cresols/cresylic acid	1319–77–3
Cumene	98–82–8
Dibenzofurans	132–64–9
Dibutylphthalate	84–74–2
Dichloroethane (1,2-) (Ethylene dichloride) (EDC)	107–06–2
Dichloropropene (1,3-)	542–75–6
Diethanolamine	111–42–2
Diethyl aniline (N,N-)	121–69–7
Diethylene glycol monobutyl ether	112–34–5
Diethylene glycol monomethyl ether	111–77–3
Diethyl sulfate	64–67–5

Compound name	CAS No.[1]
Dimethyl formamide	68–12–2
Dimethylhydrazine (1,1-)	57–14–7
Dioxane (1,4-) (1,4-Diethyleneoxide)	123–91–1
Epichlorohydrin (1-Chloro-2,3-epoxypropane)	106–89–8
Epoxybutane (1,2-)	106–88–7
Ethyl acrylate	140–88–5
Ethylbenzene	100–41–4
Ethyl chloride (Chloroethane)	75–00–3
Ethylene dibromide (Dibromomethane)	106–93–4
Ethylene glycol	107–21–1
Ethylene glycol dimethyl ether	110–71–4
Ethylene glycol monomethyl ether	109–86–4
Ethylene glycol monomethyl ether acetate	110–49–6
Ethylene glycol monophenyl ether	122–99–6
Ethylene oxide	75–21–8
Ethylidene dichloride (1,1-Dichloroethane)	75–34–3
Formaldehyde	50–00–0
Hexachloroethane	67–72–1
Hexane	110–54–3
Hydroquinone	123–31–9
Isophorone	78–59–1
Maleic anhydride	108–31–6
Methanol	67–56–1
Methyl chloride (Chloromethane)	74–87–3
Methylene chloride (Dichloromethane)	75–09–2
Methylenedianiline (4,4′-)	101–77–9
Methylene diphenyl diisocyanate	101–68–8
Methyl hydrazine	60–34–4
Methyl isobutyl ketone (Hexone) (MIBK)	108–10–1
Methyl methacrylate	80–62–6
Methyl tert-butyl ether (MTBE)	1634–04–4
Naphthalene	91–20–3
Nitrobenzene	98–95–3
Phenol	108–9–52
Phthalic anhydride	85–44–9

Compound name	CAS No.[1]
Polycyclic organic matter	50–32–8
Propionaldehyde	123–38–6
Propylene dichloride (1,2-Dichloropropane)	78–87–5
Propylene oxide	75–56–9
Quinoline	91–22–5
Styrene	100–42–5
Styrene oxide	96–09–3
Tetrachloroethane (1,1,2,2-)	79–34–5
Tetrachloroethylene (Perchloroethylene)	127–18–4
Toluene	108–88–3
Toluene diisocyanate (2,4-)	584–84–9
o-Toluidine	95–53–4
Trichlorobenzene (1,2,4-)	120–82–1
Trichloroethane (1,1,1-) (Methyl chloroform)	71–55–6
Trichloroethane (1,1,2-) (Vinyl trichloride)	79–00–5
Trichloroethylene	79–01–6
Triethylamine	121–44–8
Trimethylpentane (2,2,4-)	540–84–1
Vinyl acetate	108–05–4
Vinyl chloride (Chloroethylene)	75–01–4
Vinylidene chloride (1,1-Dichloroethylene)	75–35–4
Xylene (m-)	108–38–3
Xylene (o-)	95–47–6
Xylene (p-)	106–42–3
Xylenes (isomers and mixtures)	1330–20–7

Table 12 to Subpart EEEE of Part 63—Applicability of General Provisions to Subpart EEEE

As stated in §§63.2382 and 63.2398, you must comply with the applicable General Provisions requirements as follows:

Citation	Subject	Brief description	Applies to subpart EEEE
§63.1	Applicability	Initial applicability determination; Applicability after standard established; Permit requirements; Extensions, Notifications	Yes.
§63.2	Definitions	Definitions for part 63 standards	Yes.
§63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.

Citation	Subject	Brief description	Applies to subpart EEEE
§63.4	Prohibited Activities and Circumvention	Prohibited activities; Circumvention, Severability	Yes.
§63.5	Construction/Reconstruction	Applicability; Applications; Approvals	Yes.
§63.6(a)	Compliance with Standards/O&M Applicability	GP apply unless compliance extension; GP apply to area sources that become major	Yes.
§63.6(b)(1)–(4)	Compliance Dates for New and Reconstructed Sources	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for section 112(f)	Yes.
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.
§63.6(b)(6)	[Reserved].		
§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source	Yes.
§63.6(c)(1)–(2)	Compliance Dates for Existing Sources	Comply according to date in this subpart, which must be no later than 3 years after effective date; for section 112(f) standards, comply within 90 days of effective date unless compliance extension	Yes.
§63.6(c)(3)–(4)	[Reserved].		
§63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Area sources that become major must comply with major source standards by date indicated in this subpart or by equivalent time period (*e.g* ., 3 years)	Yes.
§63.6(d)	[Reserved].		
§63.6(e)(1)	Operation & Maintenance	Operate to minimize emissions at all times; correct malfunctions as soon as practicable; and operation and maintenance requirements independently enforceable; information Administrator will use to determine if operation and maintenance requirements were met	Yes.
§63.6(e)(2)	[Reserved].		
§63.6(e)(3)	SSM Plan	Requirement for SSM plan; content of SSM plan; actions during SSM	Yes; however, (1) the 2-day reporting requirement in paragraph §63.6(e)(3)(iv) does not apply and (2) §63.6(e)(3) does not apply to

Citation	Subject	Brief description	Applies to subpart EEEE
			emissions sources not requiring control.
§63.6(f)(1)	Compliance Except During SSM	You must comply with emission standards at all times except during SSM	Yes.
§63.6(f)(2)–(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection	Yes.
§63.6(g)(1)–(3)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§63.6(h)	Opacity/Visible Emission Standards	Requirements for compliance with opacity and visible emission standards	No; except as it applies to flares for which Method 22 observations are required as part of a flare compliance assessment.
§63.6(i)(1)–(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension	Yes.
§63.6(j)	Presidential Compliance Exemption	President may exempt any source from requirement to comply with this subpart	Yes.
§63.7(a)(2)	Performance Test Dates	Dates for conducting initial performance testing; must conduct 180 days after compliance date	Yes.
§63.7(a)(3)	Section 114 Authority	Adminsitrator may require a performance test under CAA section 114 at any time	Yes.
§63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test	Yes.
§63.7(b)(2)	Notification of Rescheduling	If you have to reschedule performance test, must notify Administrator of rescheduled date as soon as practicable and without delay	Yes.
§63.7(c)	Quality Assurance (QA)/Test Plan	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with; test plan approval procedures; performance audit requirements; internal and external QA procedures for testing	Yes.
§63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
§63.7(e)(1)	Conditions for Conducting Performance Tests	Performance tests must be conducted under representative conditions; cannot conduct performance tests during SSM	Yes.
§63.7(e)(2)	Conditions for Conducting Performance Tests	Must conduct according to this subpart and EPA test methods unless Administrator approves alternative	Yes.

Citation	Subject	Brief description	Applies to subpart EEEE
§63.7(e)(3)	Test Run Duration	Must have three test runs of at least 1 hour each; compliance is based on arithmetic mean of three runs; conditions when data from an additional test run can be used	Yes; however, for transfer racks per §§63.987(b)(3)(i)(A)–(B) and 63.997(e)(1)(v)(A)–(B) provide exceptions to the requirement for test runs to be at least 1 hour each.
§63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an intermediate or major change, or alternative to a test method	Yes.
§63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report; must submit performance test data 60 days after end of test with the Notification of Compliance Status; keep data for 5 years	Yes; however, performance test data is to be submitted with the Notification of Compliance Status according to the schedule specified in §63.9(h)(1)–(6) below.
§63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test	Yes.
§63.8(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard	Yes.
§63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of 40 CFR part 60 apply	Yes.
§63.8(a)(3)	[Reserved].		
§63.8(a)(4)	Monitoring of Flares	Monitoring requirements for flares in §63.11	Yes; however, monitoring requirements in §63.987(c) also apply.
§63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative	Yes.
§63.8(b)(2)–(3)	Multiple Effluents and Multiple Monitoring Systems	Specific requirements for installing monitoring systems; must install on each affected source or after combined with another affected source before it is released to the atmosphere provided the monitoring is sufficient to demonstrate compliance with the standard; if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup	Yes.
§63.8(c)(1)	Monitoring System Operation and Maintenance	Maintain monitoring system in a manner consistent with good air pollution control practices	Yes.
§63.8(c)(1)(i)—(iii)	Routine and Predictable SSM	Keep parts for routine repairs readily available; reporting requirements for SSM when action is described in SSM plan.	Yes.

Citation	Subject	Brief description	Applies to subpart EEEE
§63.8(c)(2)–(3)	Monitoring System Installation	Must install to get representative emission or parameter measurements; must verify operational status before or at performance test	Yes.
§63.8(c)(4)	CMS Requirements	CMS must be operating except during breakdown, out-of control, repair, maintenance, and high-level calibration drifts; COMS must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period; CEMS must have a minimum of one cycle of operation for each successive 15-minute period	Yes; however, COMS are not applicable.
§63.8(c)(5)	COMS Minimum Procedures	COMS minimum procedures	No.
§63.8(c)(6)–(8)	CMS Requirements	Zero and high level calibration check requirements. Out-of-control periods	Yes, but only applies for CEMS. 40 CFR part 63, subpart SS provides requirements for CPMS.
§63.8(d)	CMS Quality Control	Requirements for CMS quality control, including calibration, etc.; must keep quality control plan on record for 5 years; keep old versions for 5 years after revisions	Yes, but only applies for CEMS. 40 CFR part 63, subpart SS provides requirements for CPMS.
§63.8(e)	CMS Performance Evaluation	Notification, performance evaluation test plan, reports	Yes, but only applies for CEMS.
§63.8(f)(1)–(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring	Yes, but 40 CFR part 63, subpart SS also provides procedures for approval of CPMS.
§63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for CEMS	Yes.
§63.8(g)	Data Reduction	COMS 6-minute averages calculated over at least 36 evenly spaced data points; CEMS 1 hour averages computed over at least 4 equally spaced data points; data that cannot be used in average	Yes; however, COMS are not applicable.
§63.9(a)	Notification Requirements	Applicability and State delegation	Yes.
§63.9(b)(1)–(2), (4)–(5)	Initial Notifications	Submit notification within 120 days after effective date; notification of intent to construct/reconstruct, notification of commencement of construction/reconstruction, notification of startup; contents of each	Yes.
§63.9(c)	Request for Compliance	Can request if cannot comply by date	Yes.

Citation	Subject	Brief description	Applies to subpart EEEE
	Extension	or if installed best available control technology or lowest achievable emission rate (BACT/LAER)	
§63.9(d)	Notification of Special Compliance Requirements for New Sources	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date	Yes.
§63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	Yes.
§63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.
§63.9(g)	Additional Notifications When Using CMS	Notification of performance evaluation; notification about use of COMS data; notification that exceeded criterion for relative accuracy alternative	Yes; however, there are no opacity standards.
§63.9(h)(1)–(6)	Notification of Compliance Status	Contents due 60 days after end of performance test or other compliance demonstration, except for opacity/visible emissions, which are due 30 days after; when to submit to Federal vs. State authority	Yes; however, (1) there are no opacity standards and (2) all initial Notification of Compliance Status, including all performance test data, are to be submitted at the same time, either within 240 days after the compliance date or within 60 days after the last performance test demonstrating compliance has been completed, whichever occurs first.
§63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change in when notifications must be submitted	Yes.
§63.9(j)	Change in Previous Information	Must submit within 15 days after the change	No. These changes will be reported in the first and subsequent compliance reports.
§63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension; when to submit to Federal vs. State authority; procedures for owners of more than one source	Yes.
§63.10(b)(1)	Recordkeeping/Reporting	General requirements; keep all records readily available; keep for 5 years	Yes.
§63.10(b)(2)(i)–(iv)	Records Related to Startup, Shutdown, and Malfunction	Occurrence of each for operations (process equipment); occurrence of each malfunction of air pollution control equipment; maintenance on air pollution control equipment; actions during SSM	Yes.
§63.10(b)(2)(vi)–	CMS Records	Malfunctions, inoperative, out-of-	Yes.

Citation	Subject	Brief description	Applies to subpart EEEE
(xi)		control periods	
§63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test	Yes.
§63.10(b)(2)(xiv)	Records	All documentation supporting initial notification and notification of compliance status	Yes.
§63.10(b)(3)	Records	Applicability determinations	Yes.
§63.10(c)	Records	Additional records for CMS	Yes.
§63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§63.10(d)(2)	Report of Performance Test Results	When to submit to Federal or State authority	Yes.
§63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	Yes.
§63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension	Yes.
§63.10(d)(5)	SSM Reports	Contents and submission	Yes.
§63.10(e)(1)–(2)	Additional CMS Reports	Must report results for each CEMS on a unit; written copy of CMS performance evaluation; 2–3 copies of COMS performance evaluation	Yes; however, COMS are not applicable.
§63.10(e)(3)(i)–(iii)	Reports	Schedule for reporting excess emissions and parameter monitor exceedance (now defined as deviations)	Yes; however, note that the title of the report is the compliance report; deviations include excess emissions and parameter exceedances.
§63.10(e)(3)(iv)–(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions or parameter monitoring exceedance (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§63.8(c)(7)–(8) and 63.10(c)(5)–(13)	Yes.
§63.10(e)(3)(vi)–(viii)	Excess Emissions Report and Summary Report	Requirements for reporting excess emissions for CMS (now called deviations); requires all of the information in §§63.10(c)(5)–(13) and	Yes.

Citation	Subject	Brief description	Applies to subpart EEEE
		63.8(c)(7)–(8)	
§63.10(e)(4)	Reporting COMS Data	Must submit COMS data with performance test data	No.
§63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.
§63.11(b)	Flares	Requirements for flares	Yes; §63.987 requirements apply, and the section references §63.11(b).
§63.12	Delegation	State authority to enforce standards	Yes.
§63.13	Addresses	Addresses where reports, notifications, and requests are sent	Yes.
§63.14	Incorporation by Reference	Test methods incorporated by reference	Yes.
§63.15	Availability of Information	Public and confidential information	Yes.

Subpart GGGa—Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006

E.25.1 General Provisions Relating to NSPS Subpart GGGa [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR Part 60.1(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, for each compressor, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service, except when otherwise specified in 40 CFR Part 60, Subpart GGGa.

E.25.2 NSPS Requirements for Subpart GGGa [40 CFR Part 60, Subpart GGGa]

Pursuant to 40 CFR 60.590a, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart GGGa, for the emission units listed in Condition E.25.1, as specified below:

§ 60.590a Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in petroleum refineries.

(2) A compressor is an affected facility.

(3) The group of all the equipment (defined in §60.591a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, is subject to the requirements of this subpart.

(c) Addition or replacement of equipment (defined in §60.591a) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d) Facilities subject to subpart VV, subpart VVa, subpart GGG, or subpart KKK of this part are excluded from this subpart.

§ 60.591a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act, in subpart A of part 60, or in subpart VVa of this part, and the following terms shall have the specific meanings given them.

Alaskan North Slope means the approximately 69,000 square mile area extending from the Brooks Range to the Arctic Ocean.

Asphalt (also known as Bitumen) is a black or dark brown solid or semi-solid thermo-plastic material possessing waterproofing and adhesive properties. It is a complex combination of higher molecular weight organic compounds containing a relatively high proportion of hydrocarbons having carbon numbers greater than C25 with a high carbon to hydrogen ratio. It is essentially non-volatile at ambient temperatures with closed cup flash point of 445 °F (230 °C) or greater.

Equipment means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment.

In hydrogen service means that a compressor contains a process fluid that meets the conditions specified in §60.593a(b).

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.593a(c).

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

Process unit means the components assembled and connected by pipes or ducts to process raw materials and to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482–1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

§ 60.592a Standards.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §§60.482–1a to 60.482–10a as soon as practicable, but no later than 180 days after initial startup.

(b) For a given process unit, an owner or operator may elect to comply with the requirements of paragraphs (b)(1), (2), or (3) of this section as an alternative to the requirements in §60.482–7a.

(1) Comply with §60.483–1a.

(2) Comply with §60.483–2a.

(3) Comply with the Phase III provisions in §63.168, except an owner or operator may elect to follow the provisions in §60.482–7a(f) instead of §63.168 for any valve that is designated as being leakless.

(c) An owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of §60.484a.

(d) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §60.485a except as provided in §60.593a.

(e) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §§60.486a and 60.487a.

§ 60.593a Exceptions.

(a) Each owner or operator subject to the provisions of this subpart may comply with the following exceptions to the provisions of subpart VVa of this part.

(b)(1) Compressors in hydrogen service are exempt from the requirements of §60.592a if an owner or operator demonstrates that a compressor is in hydrogen service.

(2) Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E260–73, 91, or 96, E168–67, 77, or 92, or E169–63, 77, or 93 (incorporated by reference as specified in §60.17) shall be used.

(3)(i) An owner or operator may use engineering judgment rather than procedures in paragraph (b)(2) of this section to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in paragraph (b)(2) of this section shall be used to resolve the disagreement.

(ii) If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in paragraph (b)(2).

(c) Any existing reciprocating compressor that becomes an affected facility under provisions of §60.14 or §60.15 is exempt from §60.482–3a(a), (b), (c), (d), (e), and (h) provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of §60.482–3a(a), (b), (c), (d), (e), and (h).

(d) An owner or operator may use the following provision in addition to §60.485a(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86–78, 82, 90, 93, 95, or 96 (incorporated by reference as specified in §60.17).

(e) Pumps in light liquid service and valves in gas/vapor and light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the requirements of §§60.482–2a and 60.482–7a.

(f) Open-ended valves or lines containing asphalt as defined in §60.591a are exempt from the requirements of §60.482–6a(a) through (c).

(g) Connectors in gas/vapor or light liquid service are exempt from the requirements in §60.482–11a, provided the owner or operator complies with §60.482–8a for all connectors, not just those in heavy liquid service.

Subpart VVa—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

E.26.1 General Provisions Relating to NSPS Subpart VVa [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR Part 60.1(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, for each compressor, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service, except when otherwise specified in 40 CFR Part 60, Subpart VVa.

E.26.2 NSPS Requirements for Subpart VVa [40 CFR Part 60, Subpart VVa]

Pursuant to 40 CFR 60.480a, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart VVa, for the emission units listed in Condition E.26.1, as specified below:

§ 60.480a Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in §60.481a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in §60.486a(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in §60.489 is exempt from §§60.482–1a through 60.482–11a.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§60.482–1a through 60.482–11a.

(4)

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§60.482–1a through 60.482–11a.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§60.482–1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of §§60.485a(d), (e), and (f), and 60.486a(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart F must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(1)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 65, subpart F, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart F, must comply with 40 CFR part 65, subpart A.

(2) *Part 63, subpart H.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 63, subpart H, to satisfy the requirements of §§60.482–1a through 60.487a for an affected facility. When

choosing to comply with 40 CFR part 63, subpart H, the requirements of §60.485a(d), (e), and (f), and §60.486a(i) and (j) still apply.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 63, subpart H must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 63, subpart H, except that provisions required to be met prior to implementing 40 CFR part 63 still apply. Owners and operators who choose to comply with 40 CFR part 63, subpart H, must comply with 40 CFR part 63, subpart A.

§ 60.481a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA) or in subpart A of part 60, and the following terms shall have the specific meanings given them.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2006 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

Table for Determining Applicable Value for B

Subpart applicable to facility	Value of B to be used in equation
VVa	12.5
GGGa	7.0

Closed-loop system means an enclosed system that returns process fluid to the process.

Closed-purge system means a system or combination of systems and portable containers to capture purged liquids. Containers for purged liquids must be covered or closed when not being filled or emptied.

Closed vent system means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

Duct work means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.

Equipment means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.

First attempt at repair means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, P.O. Box 2300, Fairfield, NJ 07007–2300).

In gas/vapor service means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.485a(e).

In-situ sampling systems means nonextractive samplers or in-line samplers.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of §60.485a(d) specify how to determine that a piece of equipment is not in VOC service.)

Initial calibration value means the concentration measured during the initial calibration at the beginning of each day required in §60.485a(b)(1), or the most recent calibration if the instrument is recalibrated during the day (i.e., the calibration is adjusted) after a calibration drift assessment.

Liquids dripping means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

Open-ended valve or line means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

Pressure release means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

Process improvement means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

Process unit means the components assembled and connected by pipes or ducts to process raw materials and to produce, as intermediate or final products, one or more of the chemicals listed in §60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482–1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:

(1) An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours.

(2) An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

Quarter means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

Repaired means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§60.482–2a(b)(2)(ii) and (d)(6)(ii) and (d)(6)(iii), 60.482–3a(f), and 60.482–10a(f)(1)(ii), is re-monitored as specified in §60.485a(b) to verify that emissions from the equipment are below the applicable leak definition.

Replacement cost means the capital needed to purchase all the depreciable components in a facility.

Sampling connection system means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take nonroutine grab samples is not considered a sampling connection system.

Sensor means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

Storage vessel means a tank or other vessel that is used to store organic liquids that are used in the process as raw material feedstocks, produced as intermediates or final products, or generated as wastes. Storage vessel does not include vessels permanently attached to motor vehicles, such as trucks, railcars, barges or ships.

Synthetic organic chemicals manufacturing industry means the industry that produces, as intermediates or final products, one or more of the chemicals listed in §60.489.

Transfer rack means the collection of loading arms and loading hoses, at a single loading rack, that are used to fill tank trucks and/or railcars with organic liquids.

Volatile organic compounds or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in §60.2 Definitions.

§ 60.482-1a Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§60.482–1a through 60.482–10a or §60.480a(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§60.482–1a to 60.482–10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485a.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§60.482–2a, 60.482–3a, 60.482–5a, 60.482–6a, 60.482–7a, 60.482–8a, and 60.482–10a as provided in §60.484a.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§60.482–2a, 60.482–3a, 60.482–5a, 60.482–6a, 60.482–7a, 60.482–8a, or 60.482–10a, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§60.482–2a through 60.482–10a if it is identified as required in §60.486a(e)(5).

(e) Equipment that an owner or operator designates as being in VOC service less than 300 hr/yr is excluded from the requirements of §§60.482–2a through 60.482–11a if it is identified as required in §60.486a(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.

(2) The equipment is in VOC service only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.

(f)(1) If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the following table instead of monitoring as specified in §§60.482–2a, 60.482–7a, and 60.483.2a:

Operating time (percent of hours during year)	Equivalent monitoring frequency time in use		
	Monthly	Quarterly	Semiannually
0 to <25	Quarterly	Annually	Annually.
25 to <50	Quarterly	Semiannually	Annually.
50 to <75	Bimonthly	Three quarters	Semiannually.
75 to 100	Monthly	Quarterly	Semiannually.

(2) Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in paragraph (f)(1) of this section, provided the operating time of all such process units is considered.

(3) The monitoring frequencies specified in paragraph (f)(1) of this section are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator may monitor at any time during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in paragraphs (f)(3)(i) through (iv) of this section.

(i) When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.

(ii) When monitoring is conducted semiannually (*i.e.* , once every 2 quarters), monitoring events must be separated by at least 60 calendar days.

(iii) When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.

(iv) When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.

(g) If the storage vessel is shared with multiple process units, the process unit with the greatest annual amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to this subpart, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to this subpart of this part, the storage vessel is assigned to any process unit subject to subpart VV of this part. If the predominant use of the storage vessel varies from year to year, then the owner or operator must estimate the predominant use initially and reassess every 3 years. The owner or operator must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

§ 60.482-2a Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485a(b), except as provided in §60.482–1a(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in §60.482–1a(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in §60.482–1a(f).

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in §60.485a(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482–10a; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in §60.485a(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in §60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in §60.485a(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of §60.482–10a, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

§ 60.482-3a Standards: Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in §60.482–1a(c) and paragraphs (h), (i), and (j) of this section.

(b) Each compressor seal system as required in paragraph (a) of this section shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482–10a; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) of this section shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2) of this section, a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of §60.482–10a, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in §60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a) through (h) of this section if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in §60.485a(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of §60.14 or §60.15 is exempt from paragraphs (a) through (e) and (h) of this section, provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

§ 60.482-4a Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in §60.485a(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in §60.482–9a.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in §60.485a(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482–10a is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in §60.482–9a.

§ 60.482-5a Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in §60.482–1a(c) and paragraph (c) of this section.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section.

(1) Gases displaced during filling of the sample container are not required to be collected or captured.

(2) Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.

(3) Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.

(4) Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph (b)(4)(i), (ii), (iii), or (iv) of this section.

(i) Return the purged process fluid directly to the process line.

(ii) Collect and recycle the purged process fluid to a process.

(iii) Capture and transport all the purged process fluid to a control device that complies with the requirements of §60.482–10a.

(iv) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(A) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(B) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;

(C) A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;

(D) A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343 through 40 CFR 61.347; or

(E) A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

(c) In-situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

§ 60.482-6a Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482–1a(c) and paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b), and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double

block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

§ 60.482-7a Standards: Valves in gas/vapor service and in light liquid service.

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in §60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, §60.482–1a(c) and (f), and §§60.483–1a and 60.483–2a.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, §60.482–1a(c), and §§60.483–1a and 60.483–2a.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with §60.483–1a or §60.483–2a, count the new valve as leaking when calculating the percentage of valves leaking as described in §60.483–2a(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in §60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485a(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in §60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either:

(i) Becomes an affected facility through §60.14 or §60.15 and was constructed on or before January 5, 1981; or

(ii) Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

§ 60.482-8a Standards: Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485a(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §§60.482–2a(c)(2) and 60.482–7a(e).

§ 60.482-9a Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482–10a.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

§ 60.482-10a Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

(i) Conduct an initial inspection according to the procedures in §60.485a(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in §60.485a(b); and

(ii) Conduct annual inspections according to the procedures in §60.485a(b).

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in §60.486a(c).

(4) For each inspection conducted in accordance with §60.485a(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

§ 60.482-11a Standards: Connectors in gas/vapor service and in light liquid service.

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in §60.482–1a(c), §60.482–10a, or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in §60.485a(b) and, as applicable, §60.485a(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$\%C_L = C_L / C_t * 100$

Where:

$\%C_L$= Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L= Number of connectors measured at 500 ppm or greater, by the method specified in §60.485a(b).

C_t= Total number of monitored connectors in the process unit or affected facility.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors* . (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

§ 60.483-1a Alternative standards for valves—allowable percentage of valves leaking.

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in §60.487a(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with §60.482–7a(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in §60.485a(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in §60.485a(h).

§ 60.483-2a Alternative standards for valves—skip period leak detection and repair.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in §60.487(d)a.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in §60.482–7a.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in §60.482–7a but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in §60.485a(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with §60.482–7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

§ 60.484a Equivalence of means of emission limitation.

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

(2) The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4) of this section.

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in theFederal Registerand provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in theFederal Register.

(3) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e) of this section.

§ 60.485a Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the standards in §§60.482–1a through 60.482–11a, 60.483a, and 60.484a as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A–7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in §§60.482–2a(e), 60.482–3a(i), 60.482–4a, 60.482–7a(f), and 60.482–10a(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 of appendix A–7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260–73, 91, or 96, E168–67, 77, or 92, E169–63, 77, or 93 (incorporated by reference—see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 of appendix A–7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$V_{max} = K_1 + K_2 H_T$

Where:

V_{max}= Maximum permitted velocity, m/sec (ft/sec).

H_T= Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1= 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2= 0.7084 m^4 /(MJ-sec) (metric units) = 0.087 ft^4 /(Btu-sec) (English units).

(4) The net heating value (HT) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K\sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i= Concentration of sample component “i,” ppm

H_i= net heat of combustion of sample component “i” at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole.

(5) Method 18 of appendix A–6 of this part or ASTM D6420–99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420–99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504–67, 77, or 88 (Reapproved 1993) (incorporated by reference-see §60.17) shall be used to determine the concentration of sample component “i.”

(6) ASTM D2382–76 or 88 or D4809–95 (incorporated by reference-see §60.17) shall be used to determine the net heat of combustion of component “i” if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D of appendix A–7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with §60.483–1a or §60.483–2a as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$\%V_L = (V_L / V_T) * 100$

Where:

$\%V_L$= Percent leaking valves.

V_L= Number of valves found leaking.

V_T= The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with §60.482–7a(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

§ 60.486a Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(3) The owner or operator shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(b) When each leak is detected as specified in §§60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482–7a(c) and no leak has been detected during those 2 months.

(3) The identification on a connector may be removed after it has been monitored as specified in §60.482–11a(b)(3)(iv) and no leak has been detected during that monitoring.

(4) The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) Maximum instrument reading measured by Method 21 of appendix A–7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.

(5) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in §60.482–10a shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in §60.482–10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§60.482–2a, 60.482–3a, 60.482–4a, and 60.482–5a are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482–2a, 60.482–3a, 60.482–4a, and 60.482–5a.

(e) The following information pertaining to all equipment subject to the requirements in §§60.482–1a to 60.482–11a shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482–2a(e), 60.482–3a(i), and 60.482–7a(f).

(ii) The designation of equipment as subject to the requirements of §60.482–2a(e), §60.482–3a(i), or §60.482–7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

(3) A list of equipment identification numbers for pressure relief devices required to comply with §60.482–4a.

(4)(i) The dates of each compliance test as required in §§60.482–2a(e), 60.482–3a(i), 60.482–4a, and 60.482–7a(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with §60.482–1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

(7) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

(8) Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A–7 of this part and §60.485a(b).

(i) Date of calibration and initials of operator performing the calibration.

(ii) Calibration gas cylinder identification, certification date, and certified concentration.

(iii) Instrument scale(s) used.

(iv) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A–7 of this part.

(v) Results of each calibration drift assessment required by §60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(vi) If an owner or operator makes their own calibration gas, a description of the procedure used.

(9) The connector monitoring schedule for each process unit as specified in §60.482–11a(b)(3)(v).

(10) Records of each release from a pressure relief device subject to §60.482–4a.

(f) The following information pertaining to all valves subject to the requirements of §60.482–7a(g) and (h), all pumps subject to the requirements of §60.482–2a(g), and all connectors subject to the requirements of §60.482–11a(e) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with §60.483–2a:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§60.482–2a(d)(5) and 60.482–3a(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480a(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of §60.7(b) and (d) do not apply to affected facilities subject to this subpart.

§ 60.487a Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of §60.482–7a, excluding those valves designated for no detectable emissions under the provisions of §60.482–7a(f).

(3) Number of pumps subject to the requirements of §60.482–2a, excluding those pumps designated for no detectable emissions under the provisions of §60.482–2a(e) and those pumps complying with §60.482–2a(f).

(4) Number of compressors subject to the requirements of §60.482–3a, excluding those compressors designated for no detectable emissions under the provisions of §60.482–3a(i) and those compressors complying with §60.482–3a(h).

(5) Number of connectors subject to the requirements of §60.482–11a.

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486a:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in §60.482–7a(b) or §60.483–2a,

(ii) Number of valves for which leaks were not repaired as required in §60.482–7a(d)(1),

(iii) Number of pumps for which leaks were detected as described in §60.482–2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(iv) Number of pumps for which leaks were not repaired as required in §60.482–2a(c)(1) and (d)(6),

(v) Number of compressors for which leaks were detected as described in §60.482–3a(f),

(vi) Number of compressors for which leaks were not repaired as required in §60.482–3a(g)(1),

(vii) Number of connectors for which leaks were detected as described in §60.482–11a(b)

(viii) Number of connectors for which leaks were not repaired as required in §60.482–11a(d), and

(xi) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§60.483–1a or 60.483–2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions

of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

§ 60.488a Reconstruction.

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the “fixed capital cost of the new components” or the “fixed capital costs that would be required to construct a comparable new facility” under §60.15: Pump seals, nuts and bolts, rupture disks, and packings.

(b) Under §60.15, the “fixed capital cost of new components” includes the fixed capital cost of all depreciable components (except components specified in §60.488a(a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the “Applicability and designation of affected facility” section of the appropriate subpart.) For purposes of this paragraph, “commenced” means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.489a List of chemicals produced by affected facilities.

Process units that produce, as intermediates or final products, chemicals listed in §60.489 are covered under this subpart. The applicability date for process units producing one or more of these chemicals is November 8, 2006.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

PART 70 OPERATING PERMIT
CERTIFICATION

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Blvd, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify) _____

☐ Report (specify) _____

☐ Notification (specify)_____

☐ Affidavit (specify) _____

☐ Other (specify) _____

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:

Printed Name:

Title/Position:

Phone:

Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE BRANCH

100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
Phone: 317-233-0178
Fax: 317-233-6865

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Blvd, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453

This form consists of 2 pages **Page 1 of 2**

☐ This is an emergency as defined in 326 IAC 2-7-1(12)
- The Permittee must notify the Office of Air Quality (OAQ), within four (**4**) business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and
- The Permittee must submit notice in writing or by facsimile within two (**2**) working days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:
Control Equipment:
Permit Condition or Operation Limitation in Permit:
Description of the Emergency:
Describe the cause of the Emergency:

If any of the following are not applicable, mark N/A

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency? Y N Describe:
Type of Pollutants Emitted: TSP, PM-10, SO_2, VOC, NO_x, CO, Pb, other:
Estimated amount of pollutant(s) emitted during emergency:
Describe the steps taken to mitigate the problem:
Describe the corrective actions/response steps taken:
Describe the measures taken to minimize emissions:
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:

Form Completed by: _____

Title / Position:_____

Date: _____

Phone:_____

A certification is not required for this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
Compliance Data Section

PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Blvd, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453

Months: _____ **to** _____ **Year:** _____

This report shall be submitted quarterly based on a calendar year. Any deviation from the requirements, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken shall be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".
☐ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.
☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Form Completed by:_____

Title / Position: _____

Date:_____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
Compliance Data Section

Part 70 Usage Report
Submit Report Quarterly

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: Pipe line between emission units 501 and 503 and the Whiting Clean Energy Heat Recovery Steam Operator
Parameter: Steam accepted from Whiting Clean Energy
Limit: 13,200 tons per day

Month: _____ **Year:** _____

Day				Day			
1				17			
2				18			
3				19			
4				20			
5				21			
6				22			
7				23			
8				24			
9				25			
10				26			
11				27			
12				28			
13				29			
14				30			
15				31			
16				no. of deviations			

☐ No deviation occurred in this month.
☐ Deviation/s occurred in this month.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
Compliance Data Section
Part 70 Usage Report
Submit Report Quarterly

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: Pipe line between emission units 501 and 503 and the Whiting Clean Energy Heat Recovery Steam Operator
Parameter: Total steam produced by Units 501 and 503 plus amount of steam accepted from Whiting Clean Energy
Limit: 34,560 tons per day

Month: _____ **Year:** _____

Day				**Day**			
1				**17**			
2				**18**			
3				**19**			
4				**20**			
5				**21**			
6				**22**			
7				**23**			
8				**24**			
9				**25**			
10				**26**			
11				**27**			
12				**28**			
13				**29**			
14				**30**			
15				**31**			
16				**no. of deviations**			

☐ No deviation occurred in this month.
☐ Deviation/s occurred in this month.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
Compliance Data Section
Part 70 Usage Report
Submit Report Quarterly

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: Pipe line between emission units 501 and 503 and the Whiting Clean Energy Heat Recovery Steam Operator
Parameter: Steam supplied by Whiting Clean Energy to BP
Limit: 8,400 tons per day

Month: _____ **Year:** _____

Day				**Day**			
1				**17**			
2				**18**			
3				**19**			
4				**20**			
5				**21**			
6				**22**			
7				**23**			
8				**24**			
9				**25**			
10				**26**			
11				**27**			
12				**28**			
13				**29**			
14				**30**			
15				**31**			
16				**no. of deviations**			

☐ No deviation occurred in this month.
☐ Deviation/s occurred in this month.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: B/S TGU
Parameter: TRS calculated as SO_2
Limit: 232.6 tons per twelve (12) consecutive month period.

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: SBS TGU
Parameter: SO_2 at 0% excess air
Limit: 39.4 tons per twelve (12) consecutive month period.

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Blvd., Whiting, Indiana 46394
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facilities: Hot oil heaters H-SP-1, H-SP-2, H-LG-1, H-LG-2, and H-LG-3
Parameter: Natural Gas Usage
Limits: The total natural gas usage shall not exceed 255 million cubic feet (MMCF) per twelve (12) consecutive month period.

QUARTER: _____ YEAR:_____

Month	Natural Gas Usage (MMCF)	Natural Gas Usage (MMCF)	Natural Gas Usage (MMCF)
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name:	BP Products North America, Inc. – Whiting Business Unit
Source Address:	2815 Indianapolis Boulevard
Mailing Address:	P.O. Box 710, Whiting, Indiana 46394
Part 70 Permit No.:	T089-6741-00453
Facility:	Tank Cleaning Facility
Parameter:	Operating Hours
Limit:	4,440 hours per twelve (12) consecutive month period with compliance determined at the end of each month.

YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: _____
Title / Position: _____
Signature: _____
Date: _____
Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: Firing Rate (after startup of Coker #2) 10^3 mmBTU per 12 consecutive month period

Fuel Usage Limits: Existing Heaters

Facility	Limit	Facility	Limit	Facility	Limit
H-200	1601.33	F-1	259.3	F-8A	1246.55
H-300	630.72	F-2	1488.32	F-8B	1246.55
H-1X	1523.36	F-3	1576.8	F-801A	215.5
H-2	282.95	F-4	847.97	F-801B	215.5
H-3	430.99	F-5	427.49	F-801C	215.5
F-200A	1264.94	F-6	190.09	F-101	208.5
F-200B	1264.94	F-7	317.11	F-102A	208.5
WB-301	620.21	WB-302	488.81	F-401	201.5
ISOM H-1	1342.03	B-501	2809.33		

QUARTER: _____ YEAR:_____ Heater _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: Firing Rate 10^3 mmBTU per 12 consecutive month period

Fuel Usage Limits: New Units

Facility	Limit	Facility	Limit
H-201	1822.1	HU-2 RFG	2014.8
H-202	1822.1	HU-2 Total Gas	8059.2
H-203	1822.1	F-901A	411.7
H-101A	3109.8	F-901B	411.7
H-101B	2899.6	COT1 and COT2 combined	1261.4
H-102	2899.6		
B-601A	367.04		
HU-1 RFG	2014.8		
HU-1 Total Gas	8059.2		

QUARTER: _____ YEAR:_____ Heater _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: Coke Storage and Handling

Facility — Limit

New Coker (#2 Coker) (after permanent shutdown of No. 11B Coker) --- 2,190,000 tons per 12 consecutive month period

QUARTER: _____ YEAR:_____ Coker _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: Gasoline Loaded, after installation of VRU/VCU
Facility: Marine Loading Dock
Limit: 4,000,000 barrels per 12 consecutive month period

QUARTER: _____ YEAR:_____ Fuel _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period) After startup of Coker #2
H-200	8.9
H-300	3.5
H-1X	8.4
H-2	1.6
H-3	2.4

QUARTER: _____ YEAR:_____ Coker _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit
ISOM H-1	7.4 tons per 12 month period after startup of Coker #2

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period)
F-200A	7.0 (after startup of Coker #2)
F-200B	7.0 (after startup of Coker #2

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit
F-401	1.1 tons per 12 month period after startup of Coker #2

QUARTER: _____ YEAR:_____ Coker _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: Annual Firing Rate

Facility	Limit (per 12 consecutive month period)
New Boiler 1 and 2 combined	9,907,560 mmBTU

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: NOx, SO2 and CO emissions

Facility	Limit (tons per 12 consecutive month period)
New Boiler 1 and 2	NOx = 322.0 (combined total) SO2 = 24.9 (each) CO = 118.9 (combined total)

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period) After startup of Coker #2
F-1	1.4
F-8A	6.9
F-8B	6.9
F-2	8.2
F-3	8.7
F-4	4.7
F-5	2.4
F-6	1.1
F-7	1.8

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position:_____

Signature: _____

Date: _____

Phone:_____

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OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

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Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period) After startup of Coker #2
B-501	15.5

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
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Month 1			
Month 2			
Month 3			

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Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions (tons per 12 consecutive month period)

Facility	Limit
H-201	10.1
H-202	10.1
H-203	10.1
H-101A	17.2
H-101B	17.2
H-102	16.0
F-901A	2.3
F-901B	2.3

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Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period)
F-801A	1.2 (after startup of Coker #2)
F-801B	1.2 (after startup of Coker #2)
F-801C	1.2 (after startup of Coker #2

QUARTER: _____ YEAR:_____

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Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period)
F-101	1.2 (after startup of Coker #2)
F-102A	1.2 (after startup of Coker #2)

QUARTER: _____ YEAR:_____

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Month 1			
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Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period)
WB-301	3.4 (after startup of Coker #2)
WB-302	2.7 (after startup of Coker #2)

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
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Month 1			
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Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: NOx, SO2, and CO emissions
Facility: FCU 500

Pollutant	Limit (tons per 12 month period) After startup of Coker #2
NOx	155.3
SO2	200.3
CO	147.2

QUARTER: _____ YEAR:_____ Coker _____

Month	Column 1	Column 2	Column 1 + Column 2
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Month 1			
Month 2			
Month 3			

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Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: FCU 500
Parameter: Fresh Feed – barrels per 12 consecutive month period

After startup of Coker #2: 37.6 million barrels

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
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Month 1			
Month 2			
Month 3			

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Part 70 Quarterly Report

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Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: FCU 500
Parameter: Coke burned per 12 consecutive month period

After startup of Coker #2: 669,191,000 pounds

QUARTER: _____ YEAR:_____ Coker _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: NOx, SO2, and CO emissions
Facility: FCU 600

Pollutant	Limit (tons per 12 month period) After startup of Coker #2
NOx	49.7
SO2	190.0
CO	92.1

QUARTER: _____ YEAR:_____ Coker _____

Month	Column 1	Column 2	Column 1 + Column 2
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Month 1			
Month 2			
Month 3			

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Part 70 Permit No.: T089-6741-00453
Facility: FCU 600
Parameter: Fresh Feed – barrels per 12 consecutive month period

After startup of Coker #2: 24.09 million

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: FCU 600
Parameter: Coke burned per 12 consecutive month period

After startup of Coker #2: 428,802,000 pounds

QUARTER: _____ YEAR:_____ Coker _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: GOHT and South flares
Parameter: Fuel burned (10^3 cubic feet per 12 consecutive month period)

	Pilot Gas	Purge Gas
GOHT Flare	3,679.2	24,703.2
South Flare	3,679.2	28,908.0

QUARTER: _____ YEAR:_____

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Month 1			
Month 2			
Month 3			

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Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: HU Flare
Parameter: Fuel burned (10^3 cubic feet per 12 consecutive month period)

Pilot Gas

HU Flare 2,233.80

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
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Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: Coke Handling
Parameter: Alternative Operating Scenario

Hours of operation 438 hours in 12 consecutive month period

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
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Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: CO and NOx emissions after startup of New Coker (#2 Coker), tons per 12 consecutive month period

Facility	CO	NOx
H-201	17.3	18.2
H-202	17.3	18.2
H-203	17.3	18.2

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
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Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: CO and NOx emissions after startup of New Coker (#2 Coker), tons per 12 consecutive month period

Facility	CO	NOx
H-101A	29.5	77.7
H-101B	29.5	77.7

QUARTER: _____ YEAR:_____

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Part 70 Permit No.: T089-6741-00453
Parameter: CO and NOx emissions after startup of New Coker (#2 Coker), tons per 12 consecutive month period

Facility	CO	NOx
H-102	27.5	72.5

QUARTER: _____ YEAR:_____

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Part 70 Permit No.: T089-6741-00453
Parameter: SO2 and CO emissions after startup of New Coker (#2 Coker), tons per 12 consecutive month period

Facility	SO2	CO
COT1 and COT2(total)	194.8	55.0

QUARTER: _____ YEAR:_____

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Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: Firing rate after installation of duct burners on 3 SPS, mmBTU per 12 consecutive month period

Facility	Firing Rate
3SPS and duct burners	24,303,535

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
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Part 70 Permit No.: T089-6741-00453
Parameter: CO emissions, tons per 12 consecutive month period

Facility	CO Emissions
3SPS and duct burners	260.3

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
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Part 70 Permit No.: T089-6741-00453
Parameter: NOx and CO emissions, tons per 12 consecutive month period

Facility	CO Emissions	NOx Emissions
DHT Heater B-601A	7.3	7.3

QUARTER: _____ YEAR:_____

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Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions, tons per 12 consecutive month period

Facility	SO2 Emissions
GOHT heater F-901A	2.3
GOHT heater F-901B	2.3

QUARTER: _____ YEAR:_____

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Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: NOx and CO emissions, tons per 12 consecutive month period

Facility	NOx Emissions	CO Emissions
New HU heater HU-1	52.4	60.4
New HU heater HU-2	52.4	60.4

QUARTER: _____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
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Month 1			
Month 2			
Month 3			

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APPENDIX C

FUGITIVE DUST CONTROL PLAN

Document Level:	**3**
Document Number:	**E1105**
Document Review Date:	**1-30-2008**
Document Revision Date:	**1-30-2008**
Document Revision #	**6**

BP Whiting Business Unit

HSSE

Compliance Plans

BP Products North America Inc.
Whiting Business Unit
Whiting, Indiana

Fugitive Dust Control Plan

Maintained by the Whiting Business Unit Environmental Staff

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BP Whiting Refinery
Fugitive Dust Control Plan

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1.0 Purpose

BP Products North America Inc. owns and operates the Whiting Business Unit, which is a petroleum products refining complex located in the Northwest Indiana, Lake County municipalities of Whiting, Hammond and East Chicago herein referred to as BP Whiting or the BP Whiting Refinery.

Lake County-specific fugitive dust emissions requirements are provided in 326 IAC 6.8-10-3 for Lake County, Indiana. Pursuant to 326 IAC 6.8-10-4, BP Whiting is specifically required to comply with the provisions of this section, including the development of a Fugitive Dust Control Plan.

BP Whiting has developed this Fugitive Dust Control Plan to identify facilities or operations that are subject to a fugitive dust control limitation under 326 IAC 6.8-10-3 and control measures and practices that BP Whiting employs to achieve compliance with such limitations.

Pursuant to 326 IAC 6.8-10-4(2), a control plan (i.e., Fugitive Dust Control Plan), upon submittal to the department (i.e., IDEM), shall become a part of source's operating permit or registration condition.

2.0 Applicability

Pursuant to 326 IAC 6.8-10-1, Rule 10 of 326 IAC 6.8, applies to facilities and operations at a source specifically listed in 326 IAC 6.8-10-1(a)(2) under subparagraphs (A) through (W). BP Whiting is specifically listed under 326 IAC 6.8-10-1(a)(2)(A). †

2.1 Regulatory Basis and Scope of the Fugitive Dust Control Plan

Lake County-specific fugitive dust emissions requirements are provided in 326 IAC 6.8-10-3 for Lake County, Indiana. Pursuant to 326 IAC 6.8-10-4, BP Whiting is specifically required to comply with the provisions of this section, including the development of a Fugitive Dust Control Plan.

Sections of the Lake County fugitive dust regulation that are relevant to BP Whiting operations are summarized below:

- 326 IAC 6.8-10-1(a)(2) Applicability
- 326 IAC 6.8-10-2 Definitions
- 326 IAC 6.8-10-3(1) Paved Road/Parking Lot Opacity Limit and VEE Procedure
- 326 IAC 6.8-10-3(2) Unpaved Road/Parking Lot Opacity Limit and VEE Procedure
- 326 IAC 6.8-10-3(3) Material Transfer (e.g., Batch Loading) Opacity Limit and VEE Procedure

† The BP Whiting Refinery is identified as "Amoco Oil, Whiting Refinery" in 326 IAC 6..8-10-1(a)(2)(A).

- 326 IAC 6.8-10-3(4) Material Transfer (e.g., Continuous Transfer) Opacity Limit and VEE Procedure
- 326 IAC 6.8-10-3(5) Storage Pile Wind Erosion Opacity Limit and VEE Procedure
- 326 IAC 6.8-10-3(6) Material Transportation Activity Opacity Limit and VEE Procedure
- 326 IAC 6.8-10-3(7) Material Processing Facilities Opacity Limit and VEE Procedure
- 326 IAC 6.8-10-3(8) Dust Handling Equipment Opacity Limit and VEE Procedure
- 326 IAC 6.8-10-4 Compliance Requirements: Control Plans
- 326 IAC 6.8-10-4(4) Documentation to Show Compliance With Control Measures and Control Practices
- 326 IAC 6.8-10-4(G) Quarterly Reporting

3.0 Definitions and Abbreviations

”Batch transfer” means transfer of material onto or out of storage piles by front end loaders, trucks or cranes.

“Continuous transfer” means transfer of material onto or out of storage piles by conveyor.

“Control device” means the air pollution control equipment used to reduce particulate matter emissions released to the atmosphere.

“Dust handling equipment” means the equipment used to handle dust collected by control equipment, such as, but not limited to, a conveyor used to transfer dust from a control equipment hopper to a temporary storage container. A truck is an example of a temporary storage container. Both a conveyor and temporary storage container, in this case, are dust handling equipment.

“Facility” (pursuant to 326 IAC 1-2-27) means any one (1) structure, piece of equipment, installation or operation which emits or has the potential to emit any air contaminant. Single pieces of equipment or installations with multiple emission points shall be considered a facility for the purpose of 326 IAC 1-2.

“Fugitive particulate matter” means any particulate matter emitted into the atmosphere other than through a stack.

“IDEM” means the Indiana Department of Environmental Management

"In-Plant transportation" means transportation of material on plant transportation routes, such as railroads, and plant roads, in equipment such as trucks, railroad cars, front end loaders, conveyors, and skip hoists. The in-plant transportation might be from: 1) one process to another, 2) process equipment to waste disposal and reclamation sites and 3) one storage pile to another.

"Material" means raw process material, byproduct, intermediate product, waste product, final product, and dust collected by control equipment, having proportion of loose, dry dust equal to or greater than five-tenths percent (0.5%) as measured by the ASTM C-236 method, having potential to emit particulate emissions when disturbed by transfer, processing, and transportation activities.

"Material processing facilities" means the equipment, or the combination of different types of equipment, used to process material for use in the plant or for commercial sale. Equipment includes initial crusher, screen, grinder, mixer, dryer, belt conveyor, bucket elevator, bagging operation, storage bin and truck or railroad car loading station.

"Material transfer" means the transfer of material: 1) from processing equipment onto the ground, 2) from the ground into hauling equipment, 3) form hauling equipment onto a storage pile, 4) from a storage pile into hauling equipment for transport, or 5) into an initial hopper for further processing.

"Particulate matter" (pursuant to 326 IAC 1-2-52) means any airborne finely divided solid or liquid material, excluding uncombined water, with an aerodynamic diameter smaller than one hundred (100) micrometers (µm).

"Paved road" means an asphalt or concrete surfaced thoroughfare or right-of-way designed or used for vehicular traffic.

"Storage pile" means any outdoor storage on a source's property of "material" such as sand, limestone, gravel.

"Silt content" means the mass of an aggregate sample smaller than seventy-five (75) microns in diameter as determined by dry sieving. Silt content may be determined by using the procedures in AP-42 "Silt Analysis" Appendix C.2.3, Fifth Edition, January 1995, Supplements A through G, December 2000.

"Source" (pursuant to 326 IAC 1-2-73) means an aggregation of one (1) or more stationary emissions units that are located on one (1) piece of property or on contiguous or adjacent properties are owned or operated by the same person (or by persons under common control) and belong to a single major industrial grouping. For purposes of defining a source, two (2) or more contiguous or adjacent properties shall be considered part of a single major industrial grouping if all of the pollutant emitting activities at such contiguous or adjacent properties belong to the same major group, that is, all have the same two (2) digit Standard Industrial Classification (SIC) code as described in the Standard Industrial Classification Manual, 1987. Any stationary source (or group of stationary sources) that supports another source, where both are under common control of the same person (or persons under common control) and are located on contiguous or adjacent properties, shall be considered a support facility and part of the same source regardless of the two (2) digit SIC code for that support facility. A stationary source (or group of stationary sources) is considered a support facility to a source if at least fifty percent (50%) of the output

of the support facility is dedicated to the source. A source does not include mobile sources, non-road engines, or non-road vehicles.

"Transfer point" means a point in a conveying operation where the material is transferred to or from a belt conveyor, except where the material is being transferred to a storage pile.

“Unpaved road” means a thoroughfare or right-of-way other than a paved road designed or used for vehicular traffic.

"Vent" means an opening through which there is mechanically induced airflow for the purpose of exhausting air carrying particulate matter emissions from one (1) or more items of material processing equipment from a building.

“VEE” means Visible Emissions Evaluation, which is a means to determine opacity by EPA Method 9 located in Appendix A of 40 CFR 60.

4.0 Description of Affected Facilities and Operations

4.1 Source Location and Affected Facilities

As required per 326 IAC 6.8-10-4(3)(A), the name and address of the source covered by this plan and of the owner or operator responsible for the execution of this plan are included below:

BP Products North America Inc.
BP Whiting Business Unit
2815 Indianapolis Boulevard
Whiting, Indiana 46394

The following BP Whiting facilities and/or operations are affected by the Lake County fugitive dust emissions requirements in 326 IAC 6.8-10-4(3)(B):

- Paved Roads
- Unpaved Roads
- Parking Lots
- Storage Piles (e.g., sand, gravel and coke)
- Material Process Facilities (e.g., Coke Yard)
- Dust Handling Equipment (e.g., ESP fines collection at FCU's)
- Material Transfer Points
- Waste Disposal and Reclamation Sites (e.g., Catalyst/Sludge Staging Area referred to as the

"Cat Pad")

As required under 326 IAC 6.8-10-4(3)(C), a plot plans of BP Whiting, including the location of facilities and/or operations identified above is provided in Drawing No. D-3000-G-0002 and Drawing Nos. 3000-G-0201 through -0203, which are located in Appendix A. Also, as required under 326 IAC 6.8-10-4(3)(D), the following subsections provide descriptions of the facilities listed above.

4.2 Refinery Road System Including Paved and Unpaved Roads and Parking Lots

There are approximately 37 miles of roads located on-site at the BP Whiting Refinery ranging in width from 8 feet to 20 feet. Paved surfaces total about 35 miles, with the remainder of the roadway system consisting of unpaved surfaces. Unpaved roads are located in infrequently travelled portions of the refinery. In addition, there are approximately 15 main parking lots or areas within BP Whiting with many small parking areas adjacent to control rooms and other facilities within the refinery. Of the main parking areas, there are eight paved parking lots that cover approximately 5 acres and seven unpaved parking lots that cover approximately 15 acres.

The total number of vehicles travelling on the refinery road system varies widely and is estimated to range between 500 vehicles per day and 1,800 vehicles per day, depending upon the day of the week (i.e., weekend vs. weekday) and activities occurring at the refinery (e.g., unit turnarounds, new project construction, etc.) with an estimated average vehicle weight of 4 tons on paved surfaces and 2 tons on unpaved surfaces. The annual total vehicle miles travelled (VMT) is estimated to be approximately 690,000 miles. The maximum speed limit within the refinery is 20 miles per hour.

4.2.1 Paved Surfaces

Fugitive dust emissions estimates for paved surfaces are estimated using the following U.S. EPA AP-42 (AP-42) methodology:

$$E_{ext} = [k(sL/2)^{0.65}(W/3)^{1.5} - C](1 - P/4N)$$

Where,

E_{ext} = annual or other long-term average emission factor, lb/VMT

k = particle size multiplier, lb/VMT

sL = road surface silt loading (g/m2)

W = average weight (tons) of the vehicles traveling the road

C = emission factor for 1980's vehicle fleet exhaust, brake wear and tire wear (lb/VMT)

P = number of "wet" days with at least 0.01 in. of precipitation during the averaging period (120 days for Whiting, IN)

N = number of days in the averaging period (e.g., 365 days for annual)

The AP-42 paved road particle size multiplier (k) for PM_{10} is 0.016 pounds per VMT. The default value for silt loading (sL) for wintertime baseline conditions in areas that experience frozen precipitation with initial peak additive contribution from application of antiskid material is 2 g/m^2. The AP-42 PM_{10} emission factor for 1980's vehicle fleet exhaust, brake wear and tire wear is 0.00047 lb/VMT.

4.2.2 Unpaved Surfaces

Fugitive dust emissions estimates for unpaved surfaces at industrial sites also follow AP-42 methodology:

$$E_{ext} = k(s/12)^a(W/3)^b\ [(365- P)/365]$$

Where,

E_{ext} = annual or other long-term average emission factor, lb/VMT

k = particle size multiplier, lb/VMT

s = surface material silt content (%)

W = average weight (tons) of the vehicles traveling the road

P = number of "wet" days with at least 0.01 in. of precipitation during the averaging period (120 days for Whiting, IN)

a, b = empirical constants

For unpaved surfaces, the AP-42 road particle size multiplier (k) for PM_{10} is 1.5 pounds per VMT, and the surface material silt content (s) for industrial roads is 1.8 % based on an average vehicle weight (W) of 2 tons. The empirical constants a and b are 0.9 and 0.45, respectively, for unpaved surfaces at industrial sites.

4.3 Storage Piles

There are two permanent storage piles located within the BP Whiting refinery: one is used for the storage of rock salt for winter road maintenance and the other is a sand pile used for cleanup of leaks and spills in

the Asphalt Blending area.

The rock salt storage pile is enclosed and located on Technical Service Road between Gate 15 and the Truck Garage. The storage pile enclosure measures approximately 65 ft. (W) x 50 ft. (D) ft. with a 6 ft. high concrete wall and a semi-cylindrical, mesh cover fastened to arch supports. The maximum grade to ceiling height of the enclosure is approximately 35 ft. Both ends of the semi-cylindrical enclosure are also covered by a mesh cover from the top of the concrete wall. An approximately 20 ft. (W) x 25 ft. (H) mesh-covered sliding gate provides ingress and egress to and from the enclosure. The rock salt is typically transferred from the storage enclosure via front-end loader to dump trucks that spread the material over paved roadways and surfaces during snowy or icy conditions to make for safer traveling conditions during these periods of inclement weather.

The sand used in the Asphalt Blending Area is stored within an area enclosed by a three-sided, 15-ft high piling wall. Distribution from the storage pile is typically by a front end loader into a dump truck and transported to the area of the refinery where it is needed.

The Coke Yard also contains permanent storage piles during coke processing and handling, which is discussed in Section 4.4.

On an as-needed and required basis, temporary piles are utilized throughout the refinery as a result of such activities as soil excavation or for use and/or application at various refinery locations. The temporary piles typically consist of sand, soil, rock salt or crushed stone and are usually either piled next to the area of the where the activity occurs. Depending on the scope of the activity, distribution from a particular

temporary pile is may be accomplished using a front-end loader or manual labor. Moisture and silt content of the materials vary widely depending on the type of material.

4.4 Coke Processing and Transfer Operation Pre-CXHO – Operation Canadian Crude

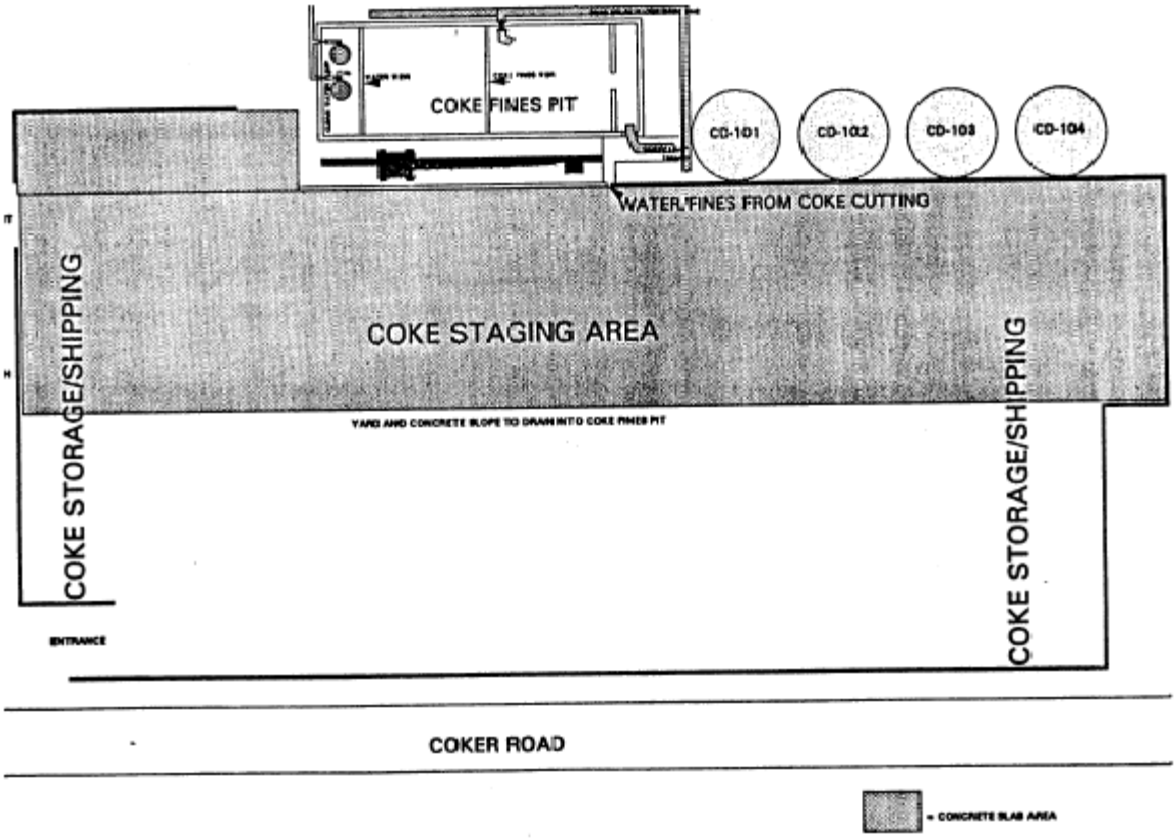
The maximum rate of coke production at the BP Whiting Refinery No. 11B Coker is estimated to be 2,000 tons per day. Potential fugitive dust emissions may result from coke handling, storage, and transfer operations that take place in the coke yard. Figure 1 is a diagram of the coke yard showing the material flow of the coke process.

Coke handling and transfer begins at the end of the coking process, where sluicing procedures are used to remove coke from filled coke drums shown as CD-101, CD-102, CD-103, and CD-104 in Figure 1. Prior to sluicing, the coke is completely contained within these pressurized vessels, where coke formation actually occurs. During the sluicing operation, the top and bottom heads of the filled coke drum are removed and a high-pressure water jet is used to cut the coke out of the drum. The wet coke falls out the drum into a pile below the drum, where it is removed by a front-end loader and transferred to the staging area for removal of excess water. Water and fines run off of the staging area into the coke fines pit, where fines are removed with a crane periodically and added to the coke pile. When excess water has drained off of the coke in the staging area, the wet coke is moved using a front-end loader to storage piles in the coke storage and shipping area of the yard.

Typically, no more than two days worth of coke is accumulated at the yard at any given time. As such, coke stored in piles typically retains relatively high moisture content during its residence within the coke

yard, which limits potential fugitive dust emissions from the area. Coke that has been in the yard the longest is shipped out first, which helps prevent the accumulation of dry coke on the piles. To remove coke from the coke yard, the material is transferred from the storage piles using a front-end loader into hauling trucks, which transports the coke offsite to customers. The hauling trucks are covered by a tarp prior to leaving the refinery to prevent the escape of potential fugitive particulate matter during transport.

Figure 1. Coke Yard Plot Plan



4.5 Coke Processing and Transfer Operation Post-CXHO – Operation Canadian Crude

A new coke handling system will be constructed to handle the coke produced from the new coker (#2 Coker) as part of the CXHO Project – Operation Canadian Crude (OCC). After the completion of the New #2 Coker, the maximum rate of coke production at the BP Whiting Refinery #2 Coker is estimated to be 6,000 tons per day. Potential fugitive dust emissions may result from coke handling, storage, and transfer operations. The coke handling system will be designed to minimize fugitive dust emissions from the coke handling process. This handling system will include enclosed conveyors and be comprised of up to 10 transfer points in the main operating scenario. Coke handling operations will be expected to operate under this main operating scenario for 95% of operating hours annually. There will also be an alternative operating scenario which will consist of three enclosed conveyors with unenclosed transfer points. This operating scenario exists as a contingency for malfunctions that could occur within the enclosed coke handling system. Coke handling operations are expected to operate under this emergency operating scenario for no more than 5% of operating hours annually. Figures 1a and 1b provide simplified process flow diagrams for these scenarios. Tables 1a and 1b detail the percentage control for each transfer point for these scenarios.

When the coking process is complete, coke is removed from the coke drums with a high pressure water spray and falls into a pit. The process is cycled between the six coke drums and coke is removed from two drums each cycle. The water saturated coke is moved from the pit to a temporary storage pile to dewater before it is moved by a bridge crane to a partially enclosed coke crusher. From the crusher the coke is conveyed in an enclosed conveyor to a transfer tower. The coke is then transferred using a series

of enclosed conveyors to either the day bin for loadout into rail cars, or if necessary to the enclosed coke storage pile for temporary storage. When coke is transferred from the enclosed storage pile to the day bin for loadout into rail cars, a series of enclosed conveyors are used for the transfer. From the day bin, coke will be loaded into rail cars using a telescopic chute to minimize particulate emissions. Particulate emissions from the storage and handling of the coke occur at various transfer points associated with the crusher, covered conveyors, day bin, and load out into the rail cars.

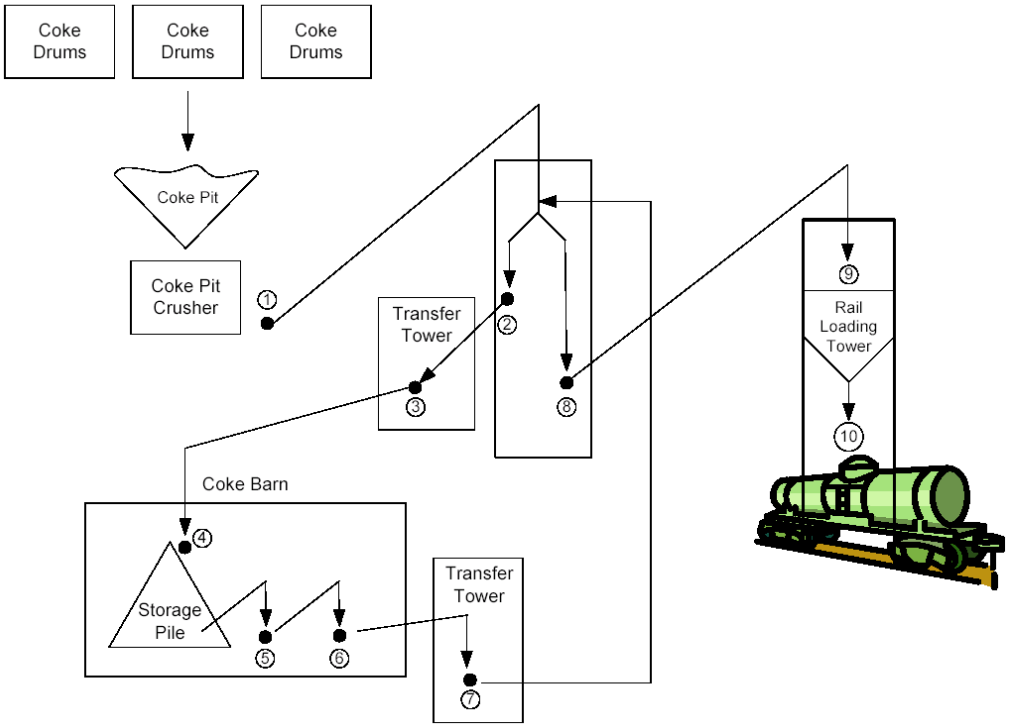


Figure 1a. Coke Handing and Storage – Main Operating Scenario

Table 1a. Percentage of Control for Transfer Points.

Transfer Point(s)	Percentage Control	Description of Control
1,10	70 %	enclosed conveyors and water spray
2 - 9	90 %	enclosed building and water spray

Figure 1b. Coke Handing and Storage – Alternate Operating Scenario

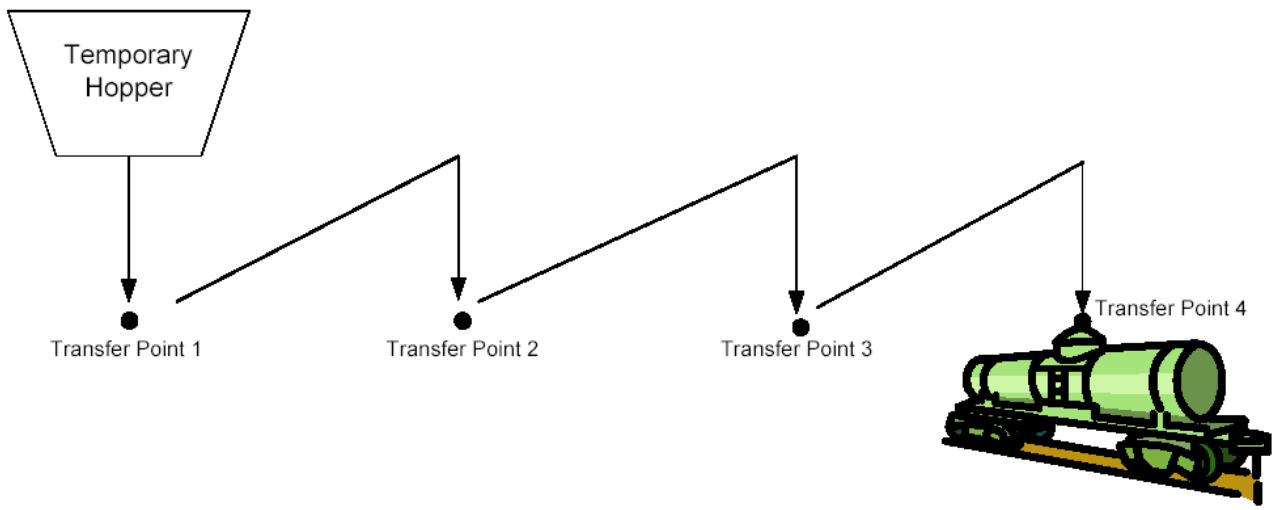


Figure 1b. Coke Handing and Storage – Alternate Operating Scenario

Table 1b. Percentage of Control for Transfer Points.

Transfer Point(s)	Percentage Control	Description of Control
1-3	40 %	enclosed conveyors
4	0 %	no control

4.6 Dust Handling Equipment (e.g., ESP Fines Collection at FCU's)

The Fluidized Catalytic Cracking Unit (FCU) utilizes a zeolytic catalyst to convert (i.e., crack) gas oil into more valuable products, including gasoline components, by circulating the catalyst between a reactor and a regenerator through a riser where gas oil comes into contact with the catalyst and the cracking occurs. BP Whiting Refinery uses two FCU's, FCU 500 and FCU 600, which are rated at 115 MM barrels of feed per day and 80 MM barrels of feed per day, respectively. Spent catalyst contained in flue gas from catalyst regeneration in the regenerators passes through an Electrostatic Precipitator (ESP), K-501 and K-502 at FCU 500 and K-701A and K-701B at FCU 600, which removes the fine spent catalyst particles prior to discharging to the atmosphere.

Catalyst fines collected in the ESP's collection bins are periodically emptied via vacuum truck and transported to the spent catalyst bin (F-52) where spent catalyst is accumulated before being transferred off-site where it is used in the cement industry. The spent catalyst bin is equipped with a cyclone separator for particulate emissions control.

4.7 Waste Disposal and Reclamation Sites (Cat Pad)

The Cat Pad is a spent catalyst/sludge staging area that is maintained as a permanent facility for storing and dewatering catalyst and sludge removed from various refinery units prior to disposal, including spent catalyst, heat exchanger sludge and oil- or water-soaked debris. Material is delivered to the Cat Pad by trucks or in drums typically in a wetted state. Transfer of material on the pad is performed using a front-end loader. Materials that are sent to the pad in a dry condition are usually wetted down with water after

dumping onto the pad to minimize the generation of fugitive particulate emissions. When materials are ready for transfer out of the area, a front-end loader is used to load the materials onto transport vehicles (including roll-off bins) for disposal in accordance with federal, state and local waste and hazardous-waste regulations.

Because a wide variety of materials are handled at the staging area, moisture and silt content of materials handled varies.

5.0 Control Measures and Practices

Pursuant to 326 IAC 6.8-10-4(3)(E) the following subsections provide descriptions of proposed control measures and practices the BP Whiting will employ to achieve compliance with the emission limitations.

5.1 Refinery Road System

Control measures and practices for BP Whiting's refinery road system are provided below for paved roads and unpaved roads.

5.1.1 Main Paved Roads

The main roads in the refinery are paved and shall be swept two times per week during the months of March through November. In the event of an unforeseen problem (such as, but not limited to, equipment failure, heavy rainfall, etc.), road sweeping shall be rescheduled. The road sweeps shall continue on a two times per week schedule during the months of November through March, weather permitting. Because weather conditions in the cold, winter months (i.e., November through March) can interfere with road sweeping and also in some cases obviate the need for it (e.g., rainfall and/or snowy conditions), alternate sweeping dates shall not be scheduled for those days when sweeping cannot occur.

Less traveled paved roads within the refinery (excluding tank fields) shall be swept on an as-needed basis as determined by Environmental Superintendent or their delegate. The refinery has a 20 mph speed limit throughout the facility that is enforced by plant security, which minimizes fugitive dust from road traffic.

Pursuant to 326 IAC 6.8-10-3(1), BP Whiting shall implement control measures as specified by 326 IAC 6.8-10-4(3)(F) within 24 hours after notification by IDEM or the U.S. EPA of violating the average instantaneous opacity limit. In addition, when requested by IDEM or U.S. EPA after an exceedance of the opacity limit is observed by a representative of either agency, BP Whiting shall initiate a compliance check with the silt loading limit. IDEM may require a revision of this Fugitive Dust Control Plan if the test shows an exceedance of the surface silt loading limit.

5.1.1.1 List of Conditions That Will Prevent Control Measures and Practices From Being Applied

Pursuant to 6.8-10-4(3)(F), conditions that will prevent control measures and practices for paved roads and parking lots from being implemented include, but are not limited to, the following:

- Extended periods of roadway or parking lot closures (e.g., due Personnel Exposure Minimization Plans (PEMP) during unit shutdowns and startups or due to road closure for maintenance and repair)

- Extended periods due inclement weather (e.g., wind storms, flooding, etc.)

- Extended number of consecutive Ozone Action Days

Note: Ozone Action Days are declared by IDEM when the state meteorologists predict that ground-level ozone could reach levels that pose health risks to sensitive groups. On such days, voluntary reduction is requested of affected citizenry, including industry, to reduce their contribution to the formation of ground-level ozone (e.g., the use of fuel fired equipment such as road sweepers).

5.1.1.2 Alternative Control Practices and Measures That Will Achieve Compliance With the Limit

BP Whiting will determine, at the time of notification by IDEM or U.S. EPA of violating the average instantaneous opacity limit for paved roadways and parking lots, measures that will achieve this average instantaneous opacity limit taking into consideration current meteorological conditions, operations and activities occurring at the refinery (e.g., unit turnarounds). Potential measures that may be considered, include, but are not limited to, the following:

- Limiting driving into and in the refinery to only essential personnel and emergency responders

- Stopping certain activities or jobs that are determined to be contributing to or aggravating the paved road and parking lot average instantaneous opacity limit.

5.1.2 Unpaved Areas

Unpaved areas of the refinery shall be treated with water or chemical solution by spray truck application on an as-needed basis as determined by the Environmental Superintendent or their delegate. A major factor in determining the need for spray truck application is the amount and frequency of precipitation that the BP Whiting Refinery receives, particularly during the hot, summer weather season.

Areas that will potentially be treated by spray tuck application include the J&L road system, the area surrounding the catalyst/sludge staging pad, unpaved parking areas and tank farm areas.

5.2 Storage Piles

As described in Section 3.3, the rock salt storage pile is enclosed by a concrete-lined, mesh covered structure to protect it from the elements, which also controls fugitive particulate emissions from wind erosion.

The sand in the Asphalt Area is stored within a 3-sided 15 ft. high piling wall, a.k.a. “sandbox”, for containment and fugitive particulate control from wind erosion.

5.3 Coke Handling, Storage, and Trucking Pre-CXHO – Operation Canadian Crude

The moisture content in the coke at the staging area (i.e., coke immediately following sluicing) is sufficiently high to prevent fugitive dust emissions, typically between approximately 5 to 15 percent.

Coke moved from the staging area to the coke yard is stored within an area with a 15-foot high piling wall for containment and wind control. The coke pile is properly graded to keep pile height from exceeding the wall height.

To control fugitive dust emissions from truck loading and truck transfer operations, all trucks leaving the coke yard must be tarped to cover the transported coke. Coke trucks are inspected by plant security personnel prior to leaving the refinery fence-line to ensure the loads are covered by tarps. In addition, BP Whiting utilizes a truck water spray system (except during winter months) to remove residual coke from the trucks as they leave the coke yard.

5.4 Coke Handling, Storage, and Transport Post-CXHO – Operation Canadian Crude

The moisture content of the coke in the coke pit is sufficiently high to prevent fugitive dust emissions, typically between approximately 5 to 15 percent. The moisture content of the coke throughout the coke handling and storage operation will be at a minimum 8% utilizing water spray when necessary.

Under the main coke storage and handing operating scenario, coke is transferred from the coke pit crusher to a covered conveyor providing a 70% emissions reduction. The coke is then transferred up to 8 times via enclosed conveyors in enclosed buildings providing a 90% emissions reduction. The final transfer point from the day bin into a rail car using telescopic chute is partially enclosed providing 70% emissions reduction.

Under the alternate coke storage and handling operating scenario, coke is transferred from a temporary

hopper via three enclosed conveyors providing 40% emissions reduction. The final transfer into the rail car is uncontrolled.

5.5 Cat Pad

Material delivered to the Cat Pad by trucks or in drums is typically in a wetted state. Materials that are transported to the Cat Pad in a dry state are wetted down upon delivery as necessary to control fugitive dust emissions.

6.0 Visible Emissions Evaluations

BP Whiting personnel shall perform visible emissions evaluations (VEE's) to determine the opacity of fugitive particulate emissions resulting from the various sources of fugitive dust, as provided in this section. The VEE's will provide the data required by 326 IAC 6.8-10-4(3)(E) that prove the effectiveness of the control measures and practices described in Section 5.0.

6.1 VEE's of Refinery Roadways and Parking Lots

BP Whiting shall conduct quarterly VEE's of the refinery roadways and parking lots.

6.1.1 Paved Surfaces

Pursuant to 326 IAC 6.8-10-3(1), the average instantaneous opacity of fugitive particulate emissions for paved surfaces shall not exceed 10%.

The average instantaneous opacity shall be the average of twelve (12) VEE's of instantaneous opacity readings taken for four (4) vehicle passes consisting of three (3) opacity readings for each vehicle pass. The three (3) opacity readings for each vehicle pass shall be taken as follows:

- The first reading will be taken at the time of emission generation
- The second reading will be taken five (5) seconds later
- The third reading will be taken five (5) seconds after the second reading (i.e., ten (10) seconds

after the first).

The three (3) readings will be taken at the point of maximum opacity. The observer will stand approximately fifteen (15) feet from the plume and at approximately right angles to the plume. Each reading shall be taken approximately four (4) feet above the surface of the roadway. Particular consideration will be give to the coke truck routes within the refinery.

6.1.2 Unpaved Surfaces

Pursuant to 326 IAC 6.8-10-3(2), the average instantaneous opacity of fugitive particulate emissions for unpaved surfaces shall not exceed 10%.

The average instantaneous opacity shall be determined according to the procedure described in Section 6.1.1 above.

6.2 VEE's of Storage Piles

Pursuant to 326 IAC 6.8-10-3(5), the opacity of fugitive particulate emissions from the wind erosion of storage piles may not exceed 10% on a 6-minute average.

The VEE's to determine opacity shall be conducted quarterly in accordance with 40 CFR 60, Appendix A, Method 9, except that the opacity will be observed at approximately four (4) feet from the surface at the point of maximum opacity. The observer shall stand approximately fifteen (15) feet from the plume and

at approximately right angles to the plume.

Note: The opacity limit of fugitive particulate emissions above shall not apply during periods when application of fugitive particulate control measures is either ineffective or unreasonable due to sustained very high wind speeds. During such periods, BP Whiting shall continue to implement *reasonable* fugitive particulate control measures. Records shall be maintained for the application of such fugitive particulate control measures and the basis for a claim that meeting the opacity limitation was not reasonable given the prevailing wind conditions.

6.3 VEE's of Coke Yard Operations

BP Whiting will perform VEE's to determine the opacity of fugitive particulate emissions resulting from various coke yard operations as provided below. The VEE's shall be conducted on a quarterly basis unless otherwise specified.

6.3.1 Batch Transfer

Pursuant to 326 IAC 6.8-10-3(3)(A), the average instantaneous opacity of fugitive particulate emissions from batch transfer operations (i.e., transport of coke fines from the staging area to the coke piles via crane) shall not exceed 10%.

The average instantaneous opacity shall be three (3) instantaneous VEE's, taken as follows:

- The first reading will be taken after the end of one (1) batch loading or unloading operation

- The second reading will be taken five (5) seconds after the first reading
- The third reading will be taken five (5) seconds after the second reading (i.e., ten (10) seconds after the first).

The three (3) readings will be taken at the point of maximum opacity. The observer shall stand approximately fifteen (15) feet from the plume and at approximately right angles to the plume.

6.3.2 Continuous Transfer

Pursuant to 326 IAC 6.8-10-3(4), the opacity of fugitive particulate emissions from continuous transfer operations (i.e. continuously transfer into or out of storage piles) shall not exceed 10% on a three minute average. The opacity shall be determined using 40 CFR 60, Appendix A, Method 9. Additionally, the opacity readings shall be taken at least four feet from the point of origin.

6.3.3 Wind Erosion from Coke Yard Storage Piles

Pursuant to 326 IAC 6.8-10-3(5), the opacity of fugitive particulate emissions from the wind erosion of storage piles may not exceed 10% on a 6-minute average.

The VEE's for opacity shall be determined according to the procedure described in Section 6.2 above for VEE's of Storage Piles.

6.3.4 Material Transportation - In-Plant Material Transported by Truck or Rail

Pursuant to 326 IAC 6.8-10-3(6)(A), there shall be a zero percent (0%) frequency of visible emissions of a material (i.e., no visible emissions) during the in-plant transportation of material by truck or rail at any time. Compliance with the limit above shall be determined by 40 CFR 60, Appendix A, Method 22, except that the observation shall be taken at approximately right angles to the prevailing wind from the leeward side of the truck or vehicle. The observations shall be made within BP Whiting Refinery property boundary.

Note: Pursuant to 326 IAC 6.8-10-3(6)(A), material transported by truck or rail that is enclosed and covered shall be considered in compliance with the in-plant transportation requirement, and, as such, shall not require VEE's for opacity compliance determination.

6.3.5 Material Transportation - In-Plant Material Transported by Front-End Loader or Skip Hoist

Pursuant to 326 IAC 6.8-10-3(6)(B), opacity from particulate emissions from in-plant transportation of material by front-end loader or skip hoist shall not exceed 10%. The three (3) opacity readings shall be taken as follows:

- The first reading will be taken at the time of emission generation
- The second reading will be taken five (5) seconds later
- The third reading will be taken five (5) seconds after the second reading (i.e., ten (10) seconds

after the first).

The three (3) VEE's shall be taken at the point of maximum opacity. The observer shall stand approximately fifteen (15) feet from the plume and at approximately right angles to the plume. Each reading shall be taken approximately four (4) feet above the surface of the coke storage and shipping area of the coke yard.

6.3.6 Crusher

Pursuant to 326 IAC 6.8-10-3(7)(C), opacity of fugitive particulate emissions from a crusher at which a capture system is not used shall not exceed 15%. Compliance with this limitation shall be determined by 40 CFR 60, Appendix A, Method 9.

6.3.7 Building Enclosure

Pursuant to 326 IAC 6.8-10-3(7)(D), there shall be a zero percent frequency of visible emissions observed from a building enclosing all or part of the material processing equipment except from a vent in the building. Compliance with this standard shall be determined by 40 CFR 60, Appendix A, Method 22.

Pursuant to 326 IAC 6.8-10-3(7)(E), PM_{10} emissions from building vents shall not exceed 0.022 grains per dry standard cubic foot and 10% opacity. Compliance with the concentration standard shall be determined by 40 CFR 60, Appendix A, Method 5 or 17, and with the opacity standard by 40 CFR 60, Appendix A, Method 9.

6.4 VEE's of Dust Handling Equipment (e.g., ESP Fines Collection at FCU's)

Pursuant to 326 IAC 6.8-10-3(8), the average instantaneous opacity of fugitive particulate emissions for dust handling equipment shall not exceed 10%.

The VEE's to determine opacity shall be conducted quarterly in accordance with 40 CFR 60, Appendix A, Method 9 during the removal of spent catalyst fines from the ESP collection bins into the tote boxes at FCU 500 and FCU 600 and during the transfer spent catalyst fines from the tote boxes into the spent catalyst storage hopper located at FCU 500.

6.5 VEE's of Waste Disposal and Reclamation Sites (Cat Pad)

Pursuant to 326 IAC 6.8-10-3(6)(B), opacity from particulate emissions from in-plant transportation of material by front-end loader or skip hoist shall not exceed 10%. VEE's shall be conducted quarterly consisting of three (3) opacity readings taken as follows:

- The first reading will be taken at the time of emission generation
- The second reading will be taken five (5) seconds later
- The third reading will be taken five (5) seconds after the second reading (i.e., ten (10) seconds after the first).

The three (3) VEE's shall be taken at the point of maximum opacity. The observer shall stand approximately fifteen (15) feet from the plume and at approximately right angles to the plume. Each reading shall be taken approximately four (4) feet above the surface of the staging area.

6.6 VEE's of General Facilities or Operations

Pursuant to 326 IAC 6.8-10-3(8), any facility or operation not specified in 326 IAC 6.8-10-3 shall meet a twenty percent (20%) opacity, three (3) minute opacity standard. Compliance with this limitation shall be determined by 40 CFR 60, Appendix A, Method 9, except that the opacity standard shall be determined as an average of twelve (12) consecutive observations recorded at fifteen (15) seconds intervals. Compliance of any operations lasting less than three (3) minutes shall be determined as an average of consecutive operations recorded at fifteen (15) second intervals for the duration of the operation.

7.0 References

Code for Federal Regulations, Title 40, Part 60, Appendix A, Method 9 - Visual Determination of the Opacity of Emissions From Stationary Sources

Control of Open Sources of Fugitive Dust, U.S. EPA, September 1988.

BP Whiting Refinery Drawing Nos. E-3000-G-0201 through -0203

BP Whiting Refinery Drawing No. D-3000-G-0002

Indiana Department of Environmental Management, Title 326 Air Pollution Control Board, Article 6.8, Rule 10 - Lake County: Fugitive Particulate Matter.

U.S. EPA, “Compilation of Air Pollutant Emission Factors”, Volume 1: Stationary Point and Area Sources, AP-42 Fifth Edition, January 1995, “Silt Analysis”, Appendix C.2.3.

U.S. EPA, “Compilation of Air Pollutant Emission Factors”, Volume 1: Stationary Point and Area Sources, AP-42 Fifth Edition, January 1995, Supplements A through G, December 2000

U.S. EPA, Guidance Document, EPA 600/2-79-103, “Iron and Steel Plant Open Source Fugitive Emission Evaluation”, Appendix B.

8.0 Records

8.1 Recordkeeping

Pursuant to 326 IAC 6.8-10-4(4), the following documentation to show compliance with each fugitive dust emissions control measures and control practices shall be maintained for three (3) years and made available for inspection and copying by IDEM during working hours. Copies of records required by 326 IAC 6.8-10 described below shall be submitted to IDEM within twenty (20) working days of *a written request by IDEM*.

8.1.1 Location of Particulate Emissions from Fugitive Dust

A map or diagram showing the location of particulate matter emissions from fugitive dust sources controlled, including:

- Location
- Identification
- Length of roadways
- Width of roadways

8.1.2 Spray Application of Water or Chemical Solution to Roadways

For each spray application of water or chemical solution to roadways:

- The name and location of the roadway controlled
- The application rate
- The time of each application
- The width of each application
- The identification of each method of application
- The total quantity of water or chemical solution, the concentration and identity of the chemical
- The material safety data sheet(s) for each chemical

8.1.3 Application of Other Physical or Chemical Control Agents

For application of physical or chemical control agents not covered in Section 6.1.2, the following:

- The name of the agent
- The location of application
- The application rate
- The total quantity of agent used
- If diluted, the percent of concentration
- The material data safety sheets for each chemical

8.1.4 Records of Events Where a Control Measure Could Not Be Implemented

A logbook for records of events where a control measures (e.g., road sweeping) described within this plan

were not/could not be implemented, including a statement of explanation (e.g., weather conditions and/or work stoppage).

8.2 Reporting

Pursuant to 326 IAC 6.8-10-4(4)(G), BP Whiting shall submit a quarterly report to IDEM within thirty (30) calendar days from the end of a quarter (i.e., April 30 for the first quarter, July 30 for the second quarter, etc.). The quarterly reports shall include the following:

- The date(s) on which the required control measure(s) was not implemented
- A listing of the control measure(s) not implemented
- The reason(s) that the control measure(s) were not implemented
- Corrective action(s) taken

In cases where control measures, such as road sweeping, were performed on alternate dates due to inclement weather, the dates on which the control measures were to have been implemented shall not be included in the quarterly report.

9.0 Plan Maintenance – Management of Change

Revisions to this Fugitive Dust Control Plan may be predicated on changes in operation that result in a reduction in uncontrolled PM_{10} emissions to less than five tons per year or upon a determination that the plan is inadequate. Each category of revisions is discussed below.

Pursuant to 326 IAC 6.8-10-4(6), a source specifically listed in 326 IAC 6.8-10-1(a)(2) shall be exempt from the requirements 326 IAC 6.8-10 - Lake County: Fugitive Particulate Matter if it can demonstrate to IDEM that its uncontrolled PM_{10} emissions are less than five (5) tons per year. An exemption must be approved by both the department and by U.S. EPA as a revision to the state implementation plant.

326 IAC 6.8-10-4(8) states that IDEM may require that a source revise its control plan if either of the following applies:

- A test of surface silt loading on a paved road show that the loading is greater than 100 pounds per mile average over five roads or five road sections. The surface silt loading shall be determined using the sampling and analysis procedures in the U.S. EPA Guidance Document: EPA 600/2-79-103, "Iron and Steel Plant Open Source Fugitive Emission Evaluation", Appendix B.

- IDEM's evaluation of the control plan under 326 IAC 6.8-10(7) determines that the requirements of the control plan have not been met.

Pursuant to 326 IAC 2-7-11(c)(3), the source may implement the changes addressed in the request for an *administrative amendment* immediately upon submittal of the request. The BP Whiting Environmental Engineer for Air Permitting shall determine whether or not changes to the Fugitive Dust Control Plan meet the requirements for administrative amendments in accordance with 326 IAC 2-7-11(a) or for permit revision requirements in accordance with 326 IAC 2-7-8 and shall submit the revised Fugitive Dust Control Plan to IDEM accordingly.

The changes and/or revisions to the Fugitive Dust Control Plan shall be documented in the table below.

Revision Level	Change(s)	Author	Date
0	Initial FDCP	Unknown	11/1980
1	Update Affected Operation List and Procedures	Unknown	02/1986
2	Update Affected Operation List and Procedures	Unknown	11/1993
3	Update Affected Operation List and Procedures	Unknown	07/1996
4	Update Affected Operation List and Procedures	N. Grimmer	05/2004
5	Update to New PM Limitations for Lake Co. Under 326 IAC 6.8	E. Sekiguchi	11/2006
6	Updated New Coker (#2 Coker) Coke Processing and Transfer Operation post CXHO Project	Trinity/N. Grimmer	1/2008

Authored by: Natalie Grimmer

Approved by: Linda Wilson

Date: 1-XX-08

Date: 1-XX-08

Appendix A

Facility Plot Plans

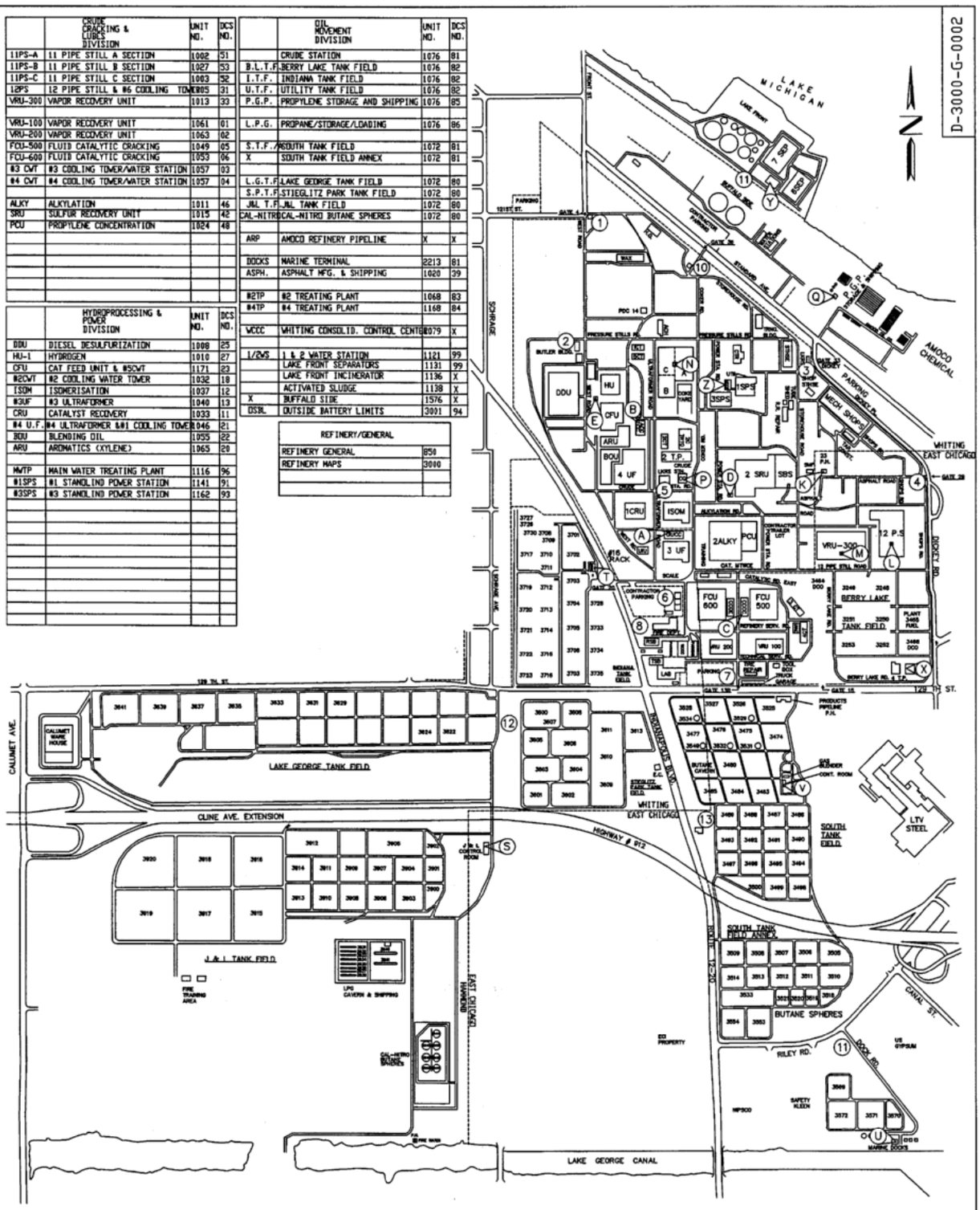
Drawing No. D-3000-G-0002
Drawing Nos. E-3000-G-0201 through -0203

	CRUDE CRACKING & LUBES DIVISION	UNIT NO.	DCS NO.
11PS-A	11 PIPE STILL A SECTION	1002	51
11PS-B	11 PIPE STILL B SECTION	1027	53
11PS-C	11 PIPE STILL C SECTION	1003	52
12PS	12 PIPE STILL & #6 COOLING TOWER	1005	31
VRU-300	VAPOR RECOVERY UNIT	1013	33
VRU-100	VAPOR RECOVERY UNIT	1061	01
VRU-200	VAPOR RECOVERY UNIT	1063	02
FCU-500	FLUID CATALYTIC CRACKING	1049	05
FCU-600	FLUID CATALYTIC CRACKING	1053	06
#3 CVT	#3 COOLING TOWER/WATER STATION	1057	03
#4 CVT	#4 COOLING TOWER/WATER STATION	1057	04
ALKY	ALKYLATION	1011	46
SRU	SULFUR RECOVERY UNIT	1015	42
PCU	PROPYLENE CONCENTRATION	1024	48

	HYDROPROCESSING & POWER DIVISION	UNIT NO.	DCS NO.
DDU	DIESEL DESULFURIZATION	1008	25
HU-1	HYDROGEN	1010	27
CFU	CAT FEED UNIT & #5CVT	1171	23
#2CVT	#2 COOLING WATER TOWER	1032	18
ISOM	ISOMERISATION	1037	12
#3UF	#3 ULTRAFORMER	1040	13
CRU	CATALYST RECOVERY	1033	11
#4 U.F.	#4 ULTRAFORMER &#1 COOLING TOWER	1046	21
BDU	BLENDING OIL	1055	22
ARU	AROMATICS (XYLENE)	1065	20
MWTP	MAIN WATER TREATING PLANT	1116	96
#1SPS	#1 STANOLIND POWER STATION	1141	91
#3SPS	#3 STANOLIND POWER STATION	1162	93

	OIL MOVEMENT DIVISION	UNIT NO.	DCS NO.
	CRUDE STATION	1076	81
B.L.T.F.	BERRY LAKE TANK FIELD	1076	82
I.T.F.	INDIANA TANK FIELD	1076	82
U.T.F.	UTILITY TANK FIELD	1076	82
P.G.P.	PROPYLENE STORAGE AND SHIPPING	1076	85
L.P.G.	PROPANE/STORAGE/LOADING	1076	86
S.T.F./X	SOUTH TANK FIELD	1072	81
X	SOUTH TANK FIELD ANNEX	1072	81
L.G.T.F.	LAKE GEORGE TANK FIELD	1072	80
S.P.T.F.	STIEGLITZ PARK TANK FIELD	1072	80
J&L T.F.	J&L TANK FIELD	1072	80
CAL-NITRO	CAL-NITRO BUTANE SPHERES	1072	80
ARP	AMOCO REFINERY PIPELINE	X	X
DOCKS	MARINE TERMINAL	2213	81
ASPH.	ASPHALT MFG. & SHIPPING	1020	39
#2TP	#2 TREATING PLANT	1068	83
#4TP	#4 TREATING PLANT	1168	84
WCCC	WHITING CONSOLID. CONTROL CENTER	8079	X
I/2WS	1 & 2 WATER STATION	1121	99
	LAKE FRONT SEPARATORS	1131	99
	LAKE FRONT INCINERATOR	1136	X
	ACTIVATED SLUDGE	1138	X
X	BUFFALO SIDE	1576	X
DSBL	OUTSIDE BATTERY LIMITS	3091	94

REFINERY/GENERAL	
REFINERY GENERAL	858
REFINERY MAPS	3000



DENOTES CLOSED ROAD

MEDICAL EMERGENCY
-CALL X1313 EMT's AT GATE 13

FIRE
-CALL X1212 SECURITY GATE 4

SPILL
-CALL X1414 CUBE COORDINATOR
-CALL PAGER #708487 ENV. INSP.
OR OPERATIONS CH. A
-IF NECESSARY- CALL LAKE FRONT AT X3248

UNIT/COMPLEX	SIGN-IN LOCATION	(X)	PRIMARY EVACUATION POINT	PEA	SECONDARY EVACUATION POINT	UNITS IN COMPLEX
UIU COMPLEX	COMPLEX CONTROL CENTER	A	GATE 20 (CONTRACTOR'S)	6	CRUDE STN LOCKER ROOM	1CRU/#2ISOM/#3UF/#2CT
ACC COMPLEX	COMPLEX CONTROL CENTER	B	BUTLER BLDG. (WEST OF H(F2))	5	CRUDE STN LOCKER ROOM	#4UF/ARU/BDU
FCUs/VRUs COMPLEX	COMPLEX CONTROL CENTER	C	GATE 13B	7	GATE 20	VRU-100/200, FCU-500/600/#3&#4CT
ALKY,SRU,PCU COMPLE	COMPLEX CONTROL CENTER	D	CRUDE STN LOCKER ROOM	5	NORTHWEST LOT 10	ALKY/SRU/TGU/PCU
CFU/DDU/HU-1 COMP.	COMPLEX CONTROL CENTER	E	BUTLER BLDG. (WEST OF H(F2))	5	STATION LOCKER ROOM	CFU/DDU/HU/#1 & #5CT
ASPHALT	ASPHALT CONTROL ROOM	K	GATE 29 (EAST OF UNIT)	4	DICKEY GATE LOCKER ROOM	BERRY LAKE TANK FIELD
#12 PIPESTILL	#12PS CONTROL ROOM	L	GATE 29 (N/E OF #12PS)	4	WEST OF #4 TREATING PLANT	
VRU-300	VRU-300 CONTROL ROOM	M	GATE 29 (N. OF SCALE GATE E. OF ASPHALT)	4	WEST OF #4 TREATING PLAN	SEC.300/350/370/380/390/MEROX/AMINE
#11 PIPESTILL	#11PS CONTROL ROOM	N	DICKEY GATE LOCKER ROOM	3	GATE 36	A/C SECTION, B SECTION (COKER)
LPG STORAGE/LOADING	J & L CONTROL ROOM	S	129th ST. & LAKE GEORGE	12	GATE 13B	
#16 LOADING RACK	CRUDE STN. CTR. ROOM	P	CRUDE STN LOCKER ROOM	5	GATE 13B	
PGP STORAGE/LOADING	PGP CONTROL ROOM	Q	DICKEY GATE	3	GATE 36	
CRUDE STATION	CRUDE STN CTR. ROOM	P	CRUDE STN LOCKER ROOM	5	GATE 13B	
J&L CONTROL COMPLEX	J & L CONTROL ROOM	S	ENTRANCE LAKE GEORGE	12	GATE 13B	CAL-NITRO/J&L CRUDE/SHIPPING/ITF/SPT
INDIANA FIELD	J & L CONTROL ROOM	S	ENTRANCE LAKE GEORGE	12	GATE 13B	
MARINE DOCKS	DOCK CONTROL ROOM	U	ENTRANCE BOAT DOCK	11	GATE 13B	BLACK OILS DOCK AREA
SOUTH TANK FIELD	SOUTH FLD CONTROL ROOM	V	GATE 18	12	GATE 13B	STF/ANNEX/BLACK OILS DOCK AREA
#2 TREATING PLANT	CRUDE STN CTR. ROOM	P	NORTHWEST LOT 10	5	GATE 13B	2A/2B/2H/2J
#4 TREATING PLANT	#4TP CONTROL ROOM	X	GATE 29B(N. OF SCALE GATE E. OF ASPHALT)	4	WEST OF #4 TREATING PLAN	4B/4C,EAST BERRY LAKE TANK FIELD
LAKEFRONT	LAKEFRONT CTR. ROOM	Y	LAKEFRONT ENTRANCE GATE	11	WHITING PARK	WATER STATIONS, BUFFALO SIDES
POWER STATIONS	UTIL. CENTRAL CTRL. ROOM	Z	DICKEY GATE	3	TRAINING BUILDING	1SPS/3SPS/MWTP/ACH
REFINERY PIPE ALLEY	CRUDE STATION CTR. ROOM	P	NORTHWEST LOT 10	6	GATE 13B	ALL UNITS

FIELD EVACUATION ALARMS

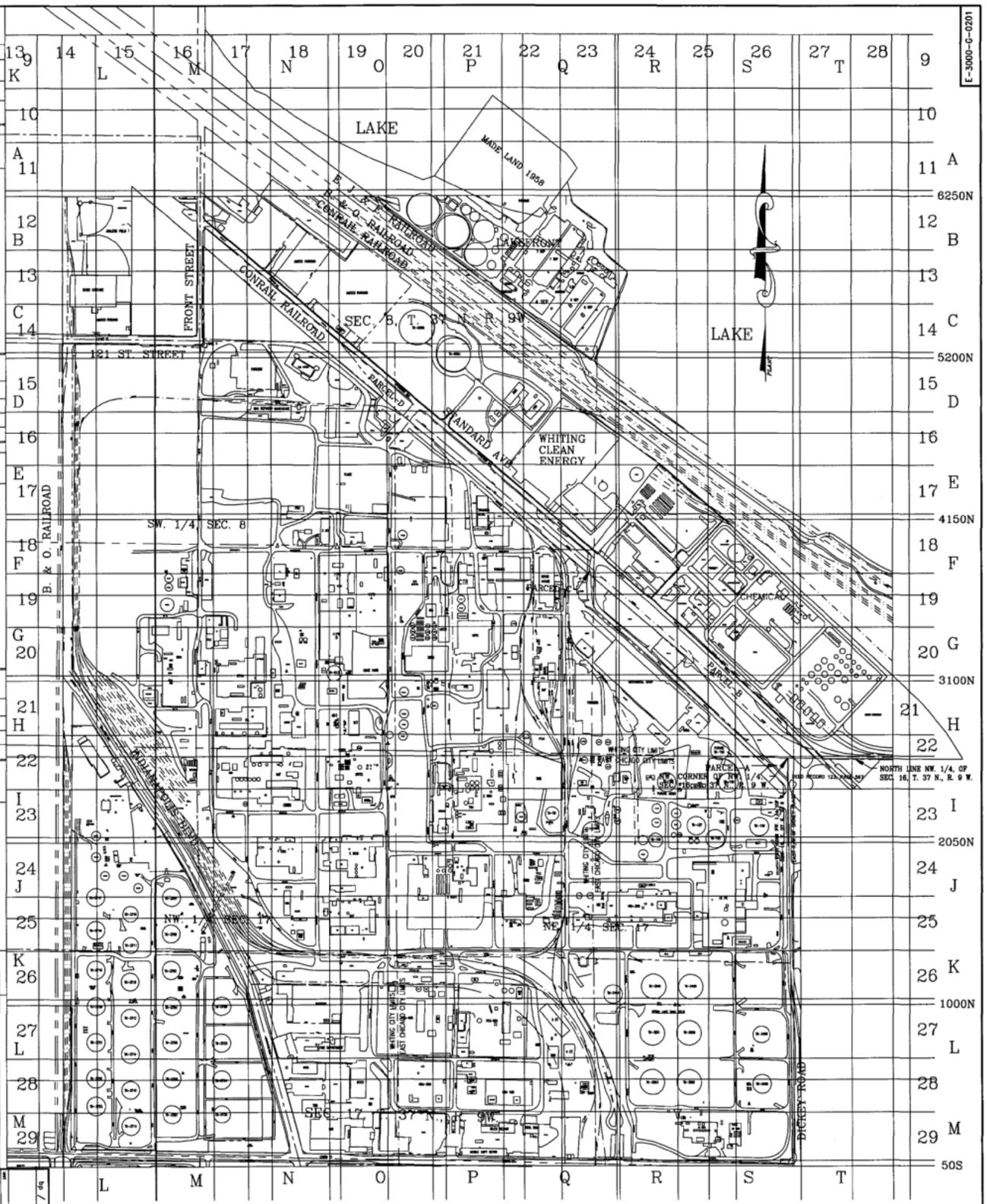
PATTERNS	WHAT DO THEY MEAN?
SERIES OF SHORTS:	EVAC ALL PERSONNEL
SERIES OF LONGS:	EVAC NON-OPER. PERSONNEL
ALTERNATING-SHORT & LONG:	EVAC NON ESSENTIAL PERSONNEL
30 SEC. LONG:	ALL CLEAR

PEA = PRIMARY EVACUATION AREA

REV.	DATE	EST.	APPR.	ISSUED FOR	BY	DATE	EST.	APPR.
7	07/24/08	GENERAL UPDATE						
6	12/01/98	UNIT/DCS NUMBERS UPDATED						
5	11-21-96	GENERAL REVISION						
4	5-13-96	GENERAL REVISION						
3	4-24-96	GENERAL REVISION						
2	1-17-96	PAGER REVISION						
1	01/30/03	UPDATED MAP PER FIELD VERIFICATION						
0	12/02/02	UPDATED EVACUATION LOCATIONS FOR VRU-300 & #4 TP						

REVISION DESCRIPTION

PREP.	CHK.	APPR.	CONF.	PROJ.	CHK.	APPR.	CONF.

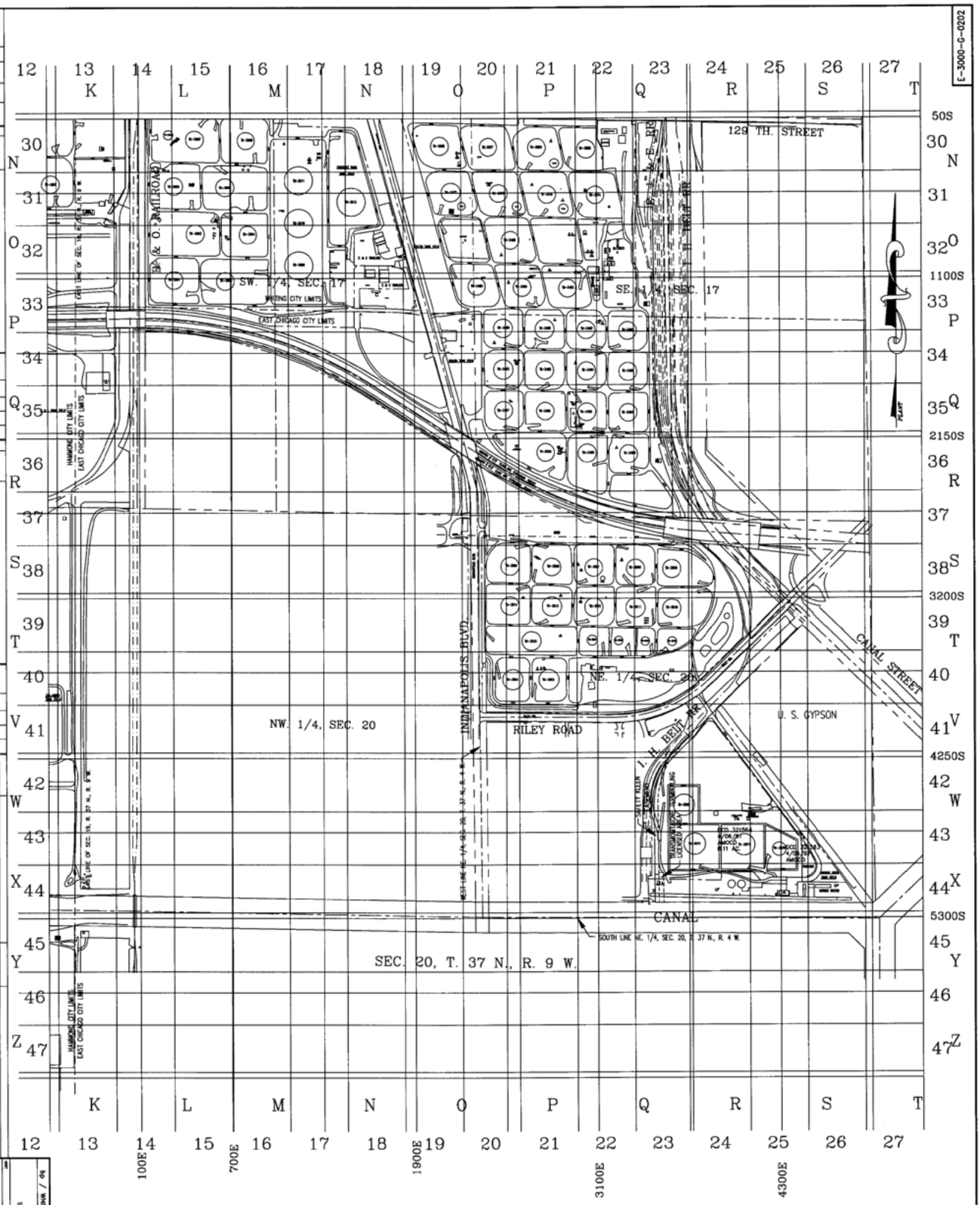


BY / WHITING BUSINESS UNIT

SITE OBO MAP

E-3000-G-0201 0

NOTIFY ENGINEERING OF ALL CHANGES



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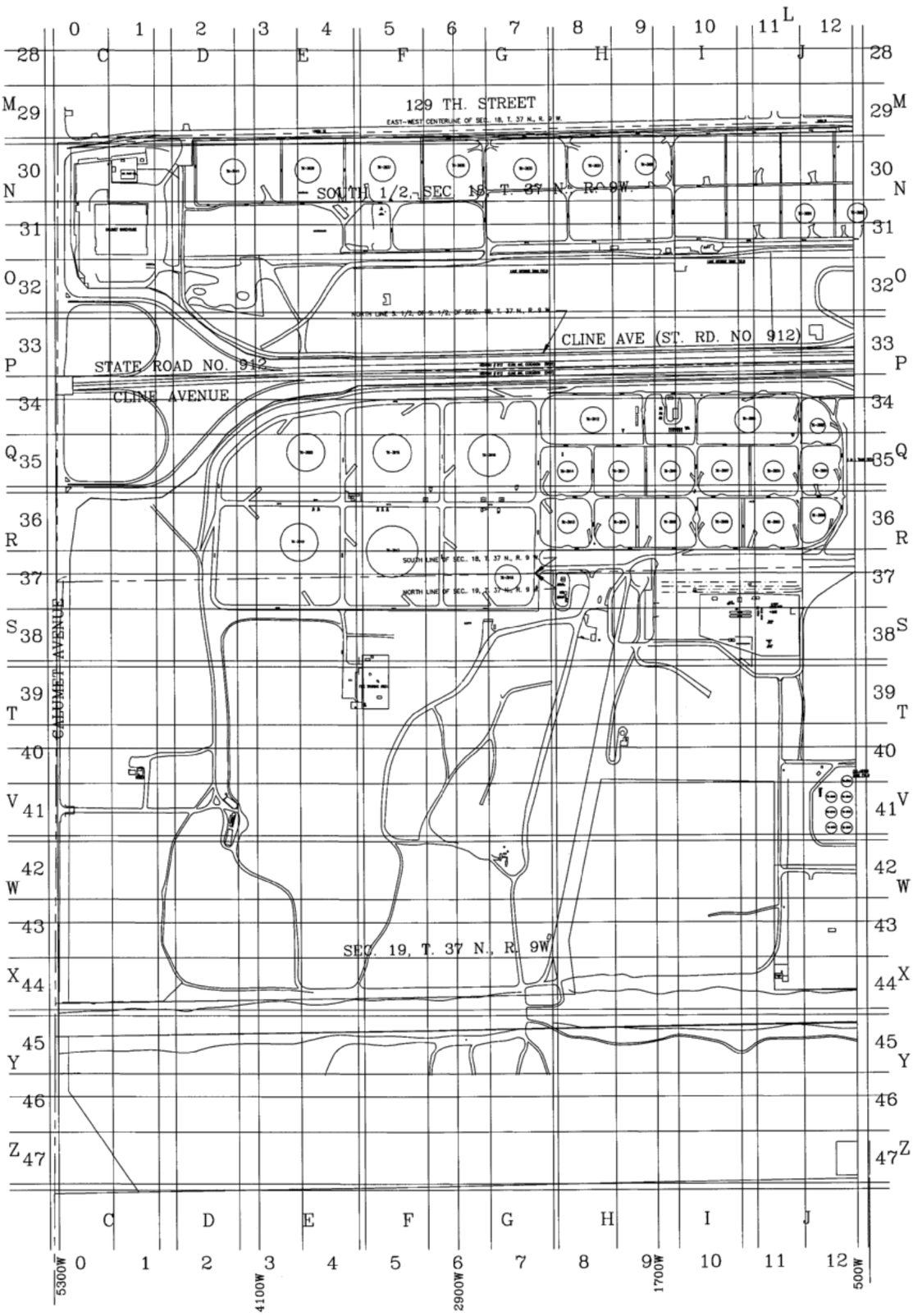
NOTIFY ENGINEERING OF ALL CHANGES

SHEET 1 OF 1

SHEET 1 OF 1

SHEET 1 OF 1

E-3000-G-0203



Dg / WHITING BUSINESS UNIT

SITE MAP

E-3000-G-0203 0

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (TSD) for a Part 70 Significant Source Modification and Significant Permit Modification.

Source Description and Location

Source Name:	BP Products North America Inc., Whiting Business Unit
Source Location:	2815 Indianapolis Blvd., Whiting Indiana 46394
County:	Lake
SIC Code:	2911 and 2869
Operation Permit No.:	T 089-6741-00453
Operation Permit Issuance Date:	December 14, 2006
Significant Source Modification No.:	089-25484-00453
Significant Permit Modification No.:	089-25488-00453
Permit Reviewer:	Madhurima Moulik

Public Notice Information

On February 7, 2008, the Office of Air Quality (OAQ) had a notice published in the Tribune newspaper in Merrillville in Lake county, and The Times newspaper in Munster in Lake county, stating that BP Products North America, Inc. - Whiting Business Unit in Whiting, Indiana had applied for a significant modification to the Part 70 Operating Permit issued on December 14, 2006, to add new equipment and modify existing equipment at the plant to accommodate additional processing of Canadian Extra Heavy Crude Oil (CXHO), also known as the Operation Canadian Crude [OCC] project. The notice also stated that OAQ proposed to issue a permit for this operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties to provide comments on whether or not this permit should be issued as proposed, that a public meeting and hearing was scheduled for March 14, 2008, and that the public comment period was extended until March 21, 2008.

On March 14, 2008, the Office of Air Quality (OAQ) held a public meeting and hearing at the Hammond Civic Center, Hammond, Indiana, for citizens and interested parties to discuss questions and concerns related to the project.

Comments Received

OAQ received comments from the following groups and government officials or agencies:

- United States Environmental Protection Agency (U.S. EPA)
- BP Products North America, Inc. - Whiting Business Unit (BP Whiting)
- State Senator Phil Boots, Senate District 23, Indiana
- Public Officials from the cities of Whiting, Hammond, East Chicago
- State Senator Dennis K. Kruse, Indiana
- St. Catherine Hospital, East Chicago, Indiana
- Lake Michigan Calumet Advisory Council
- Alliance for the Great Lakes
- Environmental Law and Policy Center
- Natural Resources Defense Council

- Legal Environmental Aid Foundation
- Save the Dunes Council
- Hoosier Chapter of the Sierra Club
- Environmental Integrity Project
- Attorney General of the State of Illinois
- Illinois Hispanic Chamber of Commerce
- Indiana and Illinois citizens living near the vicinity of the facility
- Calumet Project
- Chicago Legal Clinic, Inc. representing Respiratory Health Association of Metropolitan Chicago (RHAMC)
- Naperville Area Chamber of Commerce
- Sauk-Calumet Group of the Sierra Club (Sauk-Calumet Sierra)

IDEM also received comments from a significant number of citizens which are all addressed in this document. Not all of these commenters are identified specifically by name in this document, but all comments received during the public comment period are available for review as part of the public file.

Comments from U.S. EPA (EPA)

EPA Comment No. 1:

The netting analysis which supports the decision to permit the proposed construction for the Operation Canadian Crude (OCC) project as a minor modification is based upon emissions increases and decreases that occur during the contemporaneous period. The draft minor construction permit does not clearly identify when the OCC project will be complete; therefore, the extent of the contemporaneous period is not clear. The final construction permit should clearly identify when the OCC project is complete. This can be accomplished by identifying in the permit a specific construction event that will conclude the project.

Response:

IDEM agrees that further clarification is appropriate and has made the following changes to D.0.1 to provide this clarification:

D.0.1 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

…

(h) The installation and modification of all emission units designated as part of the CXHO project, and all projects resulting in emissions decreases necessary to ensure that this project is minor under 326 IAC 2-2 (PSD), 326 IAC 2-3 (Emission Offset), and 326 IAC 2-1.1-5 (nonattainment NSR), shall be completed no later than 180 days from the start-up of the New Coker and the re-start of the No. 12 Pipestill (after the completion of the permitted modifications), whichever occurs later. This shall be considered the completion of the CXHO project, and the end of the contemporaneous period for this project.

In addition, as a result of the above change to D.O.1, it is not necessary to specify a timeframe for the shutdown of specific units. Therefore, the following revisions have been made to D.3.5 and D.4.4:

D.3.5 Emission Offset [326 IAC 2-3], Prevention of Significant Deterioration [326 IAC 2-2] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

…

(d) The heaters H-1AN, H-1AS, H-1B, H-2, H-1CN, and H-1CX shall be permanently shutdown prior to the **completion of the CXHO project** ~~start-up of the new Coker (#2 Coker)~~.

D.4.4 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR and Emission Offset [326 IAC 2-3] Minor Limit

…

(i) The B/S TGU, SBS TGU, and SBS Cooling tower shall be permanently shutdown prior to the **completion of the CXHO project** ~~startup of the new Coker (#2 Coker)~~.

EPA Comment No. 2:

The draft permits contain particulate matter limits based on finally adopted state regulations which IDEM submitted to EPA on February 21, 2008, for inclusion into its State Implementation Plan (SIP). While EPA finds these revisions acceptable and proposed on March 14, 2008, to approve them as part of the SIP, the effective date of this federal action will be 30 days after publication of our final notice. Therefore, any final permit that IDEM issues before the SIP revision action is effective must contain both limits, reflecting the existing SIP as well as the new proposed SIP. IDEM should note in the permit that the existing limits will apply only until such time as the new limits are effective as part of the final, federally approved SIP.

Response:

The following changes have been made to the PM10 limitations included in the permit due to the revision of this rule, effective February 22, 2008. The PM10 limitations under 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008) include both filterable and condensible PM10. The conditions specifying the PM10 limitations (for filterable PM10 only) under the SIP approved 326 IAC 6.8-2-6 (as published in the Indiana Register, 28 IR 3508, on September 1, 2005) has been included as a separate condition. Emission units that are no longer in operation have been deleted from these requirements. The modified conditions are as follows:

D.1.1.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008) the Permittee shall comply with the following PM10 emission limitations for No. 11 pipe still (including nos. 11A and 11C pipe still) process heaters:

Process Heater	**PM10 Limit (lbs/MMBtu)**	**PM10 Limit (lbs/hour)**
H-1X Heater	**0.0075**	**1.863**
H2 Vacuum Heater	**0.0075**	**0.335**
H3 Vacuum Heater	**0.0075**	**0.41**
H-200 Crude Charge	**0.0075**	**1.859**
H-300 Furnace	**0.0075**	**1.341**

D.1.1**.2** Lake County PM10 **(Filterable)** Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) **(as published in the Indiana Register, 28 IR 3508, on September 1, 2005)** the Permittee shall comply with the following **filterable** PM10 emission limitations for Nos. 11A and 11C Pipe Still process heaters:

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
H-1X Heater	0.031	6.867
H2 Vacuum Heater	0.032	1.440
H3 Vacuum Heater	0.031	1.704
H-200 Crude Charge	0.032	7.866
H-300 Furnace	0.031	4.931

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.1.1.1 as part of the Indiana State Implementation Plan.

D.2.1.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

~~(a) Until the shutdown of the No. 11B Coker and Coke Pile and the heaters identified as H-101, H-102, H-103, H-104, pursuant to Commissioner's Order No. 2007-01, PM10 emissions from the stack serving No. 11 pipe still furnaces H-101, H-102, H-103, and H-104 coke preheaters shall not exceed 0.0075 lb/MMBTU and 1.49 lb/hr (total).~~

(a) Until the shutdown of the No. 11B Coker and Coke Pile and the heaters identified as H-101, H-102, H-103, H-104, pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008) PM10 emissions from the stack serving No. 11 pipe still furnaces H-101, H-102, H-103, and H-104 coke preheaters shall not exceed 0.0075 lb/MMBTU and 1.49 lb/hr (total).

D.2.1.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8]

Until the shutdown of the No. 11B Coker and Coke Pile and the heaters identified as H-101, H-102, H-103, H-104, pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005) filterable PM10 emissions from the stack serving No. 11 pipe still furnaces H-101, H-102, H-103, and H-104 coke preheaters shall not exceed 0.004 lb/MMBTU and 0.741 lb/hr (total).

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.2.1.1 as part of the Indiana State Implementation Plan.

D.3.1.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008) the Permittee shall comply with the following PM10 emission limitations for the No. 12 Pipe Still process heaters until these heaters are shutdown as part of the CXHO project:

Process Heater	**PM10 Limit (lbs/MMBtu)**	**PM10 Limit (lbs/hour)**
Stack serving H-1AN, H-1AS, H-1B Preheaters and H-2 Vacuum Heater	**0.0075**	**4.918**

(b) Until the shutdown of heaters H-1CN and H-1CX, pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the PM10 emissions from H-1CN and H-1CX shall not exceed 0.0075 lb/MMBTU for both heaters and 0.894 and 3.055 lb/hr for H-1CN and H-1CX, respectively.

D.3.1**.2** Lake County PM10 **(filterable)** Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) **(as published in the Indiana Register, 28 IR 3508, on September 1, 2005)** the Permittee shall comply with the following **filterable** PM10 emission limitations for the No. 12 Pipe Still process heaters until these heaters are shutdown as part of the CXHO project:

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
Stack serving H-1AN, H-1AS, H-1B Preheaters and H-2 Vacuum Heater	0.025	16.348

~~(b) Until the shutdown of heaters H-1CN and H-1CX, pursuant to Commissioner's Order No. 2007-01, the PM10 emissions from H-1CN and H-1CX shall not exceed 0.0075 lb/MMBTU for both heaters and 0.894 and 3.055 lb/hr for H-1CN and H-1CX, respectively.~~

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.3.1.1 as part of the Indiana State Implementation Plan.

D.4.2**.1** Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to ~~Commissioner's Order No. 2007-01~~ **326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008)**, until it is shutdown, the PM10 emissions from the B/S TGU shall not exceed 0.0075 lb/MMBTU and 0.182 lb/hr:

(b) Pursuant to **326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008)** ~~Commissioner's Order No. 2007-01~~, the PM10 emissions from the Sulfur Recovery Unit Incinerator, until it is shutdown, shall not exceed 0.0075 lb/MMBTU and 0.285 lb/hr.

D.4.2.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), until it is shutdown, the filterable PM10 emissions from each of the following units shall not exceed the following:

Emission Unit	PM_{10} Limit (lbs/MMBtu)	PM_{10} Limit (lbs/ton of Feed)	PM_{10} Limit (lbs/hour)
Sulfur Recovery Unit Incinerator	0.004	None	0.090
Beavon Stretford Tail Gas Unit (B/S TGU)	None	0.110	0.103

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.4.2.1 as part of the Indiana State Implementation Plan.

D.9.1.**1** Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

~~(a) Pursuant to Commissioner's Order No. 2007-01, PM10 emissions from the H-1 Feed Heater Furnace shall not exceed 0.0075 lb/MMBTU and 1.416 lb/hr.~~

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), PM10 emissions from the ISOM H-1 (also known as No. 2 Isomerization Feed Heater) furnace shall not exceed 0.0075 lb/MMBTU and 1.416 lb/hr.

D.9.1.2 Lake County PM_{10} (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), filterable PM10 emissions from the H-1 Feed Heater Furnace shall not exceed 0.004 lb/MMBtu and 0.704 lb/hr.

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.9.1.1 as part of the Indiana State Implementation Plan.

D.10.1.**1** Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

~~(a) Pursuant to Commissioner's Order No. 2007-01 PM_{10} emissions from the following ARU combustion units shall not exceed the following emission limitations:~~ **Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), PM_{10} emissions from the following ARU (Aromatic Recovery Unit) furnaces shall not exceed the following emission limitations:**

Process Heater	PM_{10} Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
F-200A	0.0075	1.859
F-200B	0.0075	1.859

D.10.1.2 Lake County PM_{10} (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), filterable PM_{10} emissions from the following ARU combustion units shall not exceed the following emission limitations:

Process Heater	**PM_{10} Limit (lbs/MMBtu)**	**PM10 Limit (lbs/hour)**
F-200A	**0.004**	**0.924**
F-200B	**0.004**	**0.924**

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.10.1.1 as part of the Indiana State Implementation Plan.

D.11.1.**1** Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

~~(a) Pursuant to Commissioner's Order No. the PM10 emissions from the F-401 process furnace shall not exceed 0.0075 lb/MMBTU and 0.261 lb/hr.~~

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), PM_{10} emissions from the F-401 BOU (Blending Oil Desulfurization) Process Furnace shall not exceed 0.0075 lb/MMBtu and 0.261 lb/hour.

D.11.1.2 Lake County PM_{10} (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), filterable PM_{10} emissions from the F-401 Process Furnace shall not exceed 0.004 lb/MMBtu and 0.130 lb/hour.

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.11.1.1 as part of the Indiana State Implementation Plan.

D.16.1.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

~~**(a)** Pursuant to Commissioner's Order No. 2007-01, the Permittee shall not exceed the following PM10 emission limitations for the No. 4 UF process heaters:~~

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the Permittee shall not exceed the following PM_{10} emission limitations for the No. 4 UF (Ultraformer) process heaters:

Process Heater	PM_{10} Limit (lb/MMBTU)	PM_{10} Limit (lb/hour)
Stack serving F-1 furnace, F-8A (reboiler) and F-8B (reboiler)	0.0075	2.936
F-2 (preheater furnace)	0.0075	2.131
F-3 (no. 1 reheat furnace)	0.0075	1.803
Stack serving F-4 (no. 2 reheat furnace), F-5 (no. 3 reheat furnace) and F-6 (no. 4 reheat furnace)	0.0075	2.124
F-7	0.0075	0.387

D.16.1.2 Lake County PM_{10} (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), the Permittee shall not exceed the following filterable PM_{10} emission limitations for the No. 4 UF process heaters:

Process Heater	**PM_{10} Limit (lbs/MMBtu)**	**PM_{10} Limit (lbs/hour)**
stack serving F-1, F-8A and F-8B	**0.004**	**1.459**
F-2	**0.004**	**1.059**
F-3	**0.004**	**0.896**
stack serving F-4R, F-5 and F-6	**0.004**	**1.060**
F-7	**0.004**	**0.159**

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.16.1.1 as part of the Indiana State Implementation Plan.

D.17.1.**1** Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

~~(a) Pursuant to Commissioner's Order No. 2007-01 PM10 emissions from the B-501 HU Process Heater shall not exceed 0.0075 lb/MMBTU and 2.729 lb/hr.~~

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), PM10 emissions from the HU (hydrogen unit) B-501 Process Heater shall not exceed 0.0075 lb/MMBTU and 2.729 lb/hr.

D.17.1.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), filterable PM10 emissions from the B-501 HU Process Heater shall not exceed 0.009 lb/MMBTU and 3.340 lbs/hour.

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.1.1.1 as part of the Indiana State Implementation Plan.

D.18.1.**1** Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

~~(a) Pursuant to Commissioner's Order No. 2007-01 the Permittee shall not exceed the following PM10 emission limitations for the DDU Process Heaters:~~ **Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the Permittee shall not exceed the following PM10 emission limitations for the DDU Process Heaters:**

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
WB-301	0.0075	1.106
WB-302	0.0075	

D.18.1.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), the Permittee shall not exceed the following filterable PM10 emission limitations for the DDU Process Heaters:

Process Heater	**PM10 Limit (lbs/MMBtu)**	**PM10 Limit (lbs/hour)**
WB-301	**0.004**	**0.250**
WB-302	**0.004**	**0.240**

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.18.1.1 as part of the Indiana State Implementation Plan.

D.19.1.**1** Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

~~(a) Pursuant to Commissioner's Order No. 2007-01 the PM10 from the CFHU Process Heaters F-801A, F-801B and F-801C shall not exceed 0.0075 lb/MMBTU and 0.943 lb/hr (total).~~ **Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the PM10 from each stack serving CFHU (Cat Feed Hydrotreating Unit) Process Heaters F-801A, F-801B and F-801C shall not exceed 0.0075 lb/MMBTU and 0.943 lb/hr.**

D.19.1.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), PM10 (filterable) emissions from the CFHU Process Heaters F-801A/B shall be limited to 0.004 lbs/MMBtu and 0.246 lbs/hour.

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.19.1.1 as part of the Indiana State Implementation Plan.

D.20.1.**1** Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

~~(a) Pursuant to Commissioner's Order No. 2007-01, the Permittee must comply with the following PM10 emission limitations for the CRU Process Heaters:~~ **Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the Permittee must comply with the following PM10 emission limitations for the No. 1 CRU (also known as unit ID 201) feed preheaters:**

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
F-101	0.0075	0.536
F-102A	0.0075	0.447

D.20.1.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), the Permittee must comply with the following filterable PM10 emission limitations for the CRU Process Heaters:

Process Heater	**PM10 Limit (lbs/MMBtu)**	**PM10 Limit (lbs/hour)**
F-101	**0.004**	**0.267**
F-102A	**0.004**	**0.290**

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.20.1.1 as part of the Indiana State Implementation Plan.

D.23.2.**1** Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

Until the shutdown of boilers #5, 6, and 7:

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the Permittee shall comply with the following PM10 emission limitations for the No. 1 SPS (no. 1 powerstation) boilers:

Boiler	**PM10 Limit (lbs/MMBtu)**	**PM10 Limit (lbs/hour)**
Stack serving Boilers #5, #6, and #7	**0.0075**	**5.924**

D.23.2.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Until the shutdown of boilers #5, 6, and 7:

Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) **(as published in the Indiana Register, 28 IR 3508, on September 1, 2005)**, the Permittee shall comply with the following **filterable** PM10 emission limitations for the No. 1 SPS Boilers:

Boiler	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
Stack serving Boilers #5, #6, and #7	0.016	13.244 (Total)

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.23.2.1 as part of the Indiana State Implementation Plan.

D.24.1.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), PM10 emissions from each stack serving No. 3 power station boilers #1, #2, #3, #4 and #6 shall not exceed 0.0075 pounds per million Btu heat input and 4.28 pounds per hour for each boiler.

D.24.1.2 Lake County PM10 (Filterable) Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1) **(as published in the Indiana Register, 28 IR 3508, on September 1, 2005)**, **filterable** PM10 emissions from each stack serving Boilers #1, #2, #3, #4 and #6 shall not exceed 0.030 pounds per million Btu heat input and 17.49 pounds per hour for each boiler.

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.24.1.1 as part of the Indiana State Implementation Plan.

D.32.1.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 (as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008), the Permittee must comply with the following PM_{10} emission limitations for the Asphalt facility process heaters:

Process Heater	**PM_{10} Limit (lbs/MMBtu)**	**PM_{10} Limit (lbs/hour)**
F-1 Asphalt Heater	**0.0075**	**0.089**
F-2 Steiglitz Park Heater	**0.0075**	**0.209**

D.32.1.**2** Lake County PM_{10} **(Filterable)** Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)) **(as published in the Indiana Register, 28 IR 3508, on September 1, 2005)**, the Permittee must comply with the following **filterable** PM_{10} emission limitations for the Asphalt facility process heaters:

Process Heater	PM_{10} Limit (lbs/MMBtu)	PM_{10} Limit (lbs/hour)
F-1 Asphalt Heater	0.004	0.048
F-2 Steiglitz Park Heater	0.008	0.208

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.32.1.1 as part of the Indiana State Implementation Plan.

D.34.1.**1** Lake County PM_{10} Emission Limitations [326 IAC 6.8-3-6]

Pursuant to 326 IAC 6.8-2-6(b) **(as published in the Indiana Register, Document Identification Number (DIN): 20080220-IR-32604279FRA, on February 20, 2008)**, the F-100 marine docks distillate heater shall have the following emission limits:

(a) Only natural gas shall be burned as fuel; and

(b) The PM10 emissions shall not exceed 0.0075 pounds per million Btu heat input and 0.052 pounds per hour.

D.34.1.2 Lake County PM_{10} (Filterable) Emission Limitations [326 IAC 6.8-3-6]

Pursuant to 326 IAC 6.8-6-3 (formerly 326 IAC 6-1-10.1(h)) (as published in the Indiana Register, 28 IR 3508, on September 1, 2005), the Permittee shall comply with the following requirements for process heater F-100:

(a) Only natural gas shall be burned as fuel; and

(b) The filterable PM10 emissions shall not exceed 0.003 pounds per million Btu heat input and 0.020 pounds per hour.

These filterable PM10 emission limitations shall be in effect until U.S. EPA approves the revised version of 326 IAC 6.8 specified in D.1.1.1 as part of the Indiana State Implementation Plan.

EPA Comment No. 3:

The draft permits contain requirements for units that have converted or will convert from the use of fuel oil to cleaner fuel such as natural or refinery gas (for example, the #1IA and 11C Pipe Still process heaters). The particulate matter emission limits listed for these sources should reflect the conversion to the cleaner fuel. The permit should incorporate a ban on burning fuel oil and/or specify that the lower emission limit applies, and this should be made effective upon the conversion, rather than the end of the OCC project.

Response:

Upon further review, IDEM has added the following requirements to the permit:

D.1.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

...

(d) The following heaters shall not combust any fuel oil: H-1X, H-2, H-3, H-200, H-300.

D.3.5 Emission Offset [326 IAC 2-3], Prevention of Significant Deterioration [326 IAC 2-2] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

(a) Pursuant to CP 089-2055-00453 issued on March 12, 1992, until heater H-1CX is shutdown, nitrogen oxide emissions from the 12 Pipe Still H-1CX furnace shall not exceed 0.10 lb/MMBtu. Compliance with this limit renders 326 IAC 2-3 not applicable. The H-1CX furnace shall also be equipped with low NO_x burners.

In order to render 326 IAC 2-2-8, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable:

...

(e) The following heaters and preheaters shall not combust any fuel oil: H-1AN, H-1AS, H-1B preheaters, H-2 vacuum heaters.

D.23.1 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable:

(a) The boilers #5, 6, and 7 shall not combust fuel oil; and

(b) The boilers #5, 6, and 7 shall be permanently shutdown prior to the **completion of the CXHO project.** ~~start-up of the new Coker (#2 Coker).~~

D.24.4 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee **shall not combust fuel oil at boilers # 1,2,3,4 and 5** and shall comply with the following for No. 3 Stanolind Power Station:

EPA Comment No. 4:

IDEM has incorporated into the draft operating permit entire New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs) subparts that may contain requirements applicable to various units within the facility. This approach does not make clear what requirements apply to individual emission units at the source. IDEM should provide tables in the permit that specify the applicable sections and subsections of the NSPS and NESHAPs for each affected emission unit at the facility.

Response:

In response to this comment, we have included a summary table as Appendix A of this Addendum to the Technical Support Document which outlines the regulatory applicability for the OCC project. In addition, IDEM has determined that the following portions of the federal rules contained in the draft E sections of draft permit nos. 089-25484-00453 and 089-25488-00453 are not currently applicable to BP Whiting:

Section E.18: The entire section is no longer applicable due to the shutdown of the Fluidized Bed Incinerator.

Section E.21:
40 CFR 63.7881(a)(3)(i) through (a)(3)(ii) {Note that the main paragraph (a)(3) should be kept in the permit}
40 CFR 63.7881(b)(4) and (b)(5)
40 CFR 63.7883(d)

Section E.22:
40 CFR 60.40b(b),(d),(h)(i) and (k)
40 CFR 60.42b
40 CFR 60.43b
40 CFR 60.44b(a),(b),(c),(d),(g),(j) and (k)
40 CFR 60.45b
40 CFR 60.46b(b),(d),(e)(2), (e)(4),(e)(5),(f),(g),(i) and (j)
40 CFR 60.47b
40 CFR 60.48b(a),(e)(1),(g),(h),(i),(j) and (k)
40 CFR 60.49b(a)(4),(e),(f),(j),(k),(l),(m),(n),(p),(q),(r),(s),(t),(u),(x) and (y)

Section E.23:
40 CFR 60.4207(d) and (e)
Table 6
Table 7

Section E.24:
40 CFR 63.2334(c)
40 CFR 63.2342(a)(1)(i),(a)(1)(ii), and (c)

Section E.26:
40 CFR 63.480a(d)(4)

The non-applicable portions of federal rules that were included in the E sections of the draft permit have been deleted as follows:

1. Section E.18 - 40 CFR Part 61, Subpart E – National Emission Standards for Mercury, has been deleted in its entirely, since the Fluidized Bed Incinerator is no longer in operation.

2. Section E.21

§ 63.7881 Am I subject to this subpart?

(a) This subpart applies to you if you own or operate a facility at which you conduct a site remediation, as defined in §63.7957; and this site remediation, unless exempted under paragraph (b) or (c) of this section, meets all three of the following conditions specified in paragraphs (a)(1) through (3) of this section.

(1) Your site remediation cleans up a remediation material, as defined in §63.7957.

(2) Your site remediation is co-located at your facility with one or more other stationary sources that emit HAP and meet an affected source definition specified for a source category that is regulated by another subpart under 40 CFR part 63. This condition applies regardless whether or not the affected stationary source(s) at your facility is subject to the standards under the applicable subpart(s).

(3) Your facility is a major source of HAP as defined in §63.2, except as specified in paragraph (a)(3)(i) or (ii) of this section. A major source emits or has the potential to emit any single HAP at the rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year.

~~(i) For production field facilities, as defined in §63.761, only the HAP emissions from the glycol dehydration units and storage vessels with the potential for flash emissions (both as defined in §63.761) shall be aggregated with the HAP emissions from the site remediation activities at the facility for a major source determination.~~

~~(ii) For natural gas transmission and storage facilities, HAP emissions shall be aggregated in accordance with the definition of major source in §63.1271 for a major source determination.~~

(b) You are not subject to this subpart if your site remediation qualifies for any of one of the exemptions listed in paragraphs (b)(1) through (6) of this section.

(1) Your site remediation is not subject to this subpart if the site remediation only cleans up material that does not contain any of the HAP listed in Table 1 of this subpart.

(2) Your site remediation is not subject to this subpart if the site remediation will be performed under the authority of the Comprehensive Environmental Response and Compensation Liability Act (CERCLA) as a remedial action or a non time-critical removal action.

(3) Your site remediation is not subject to this subpart if the site remediation will be performed under a Resource Conservation and Recovery Act (RCRA) corrective action conducted at a treatment, storage and disposal facility (TSDF) that is either required by your permit issued by either the U.S. Environmental Protection Agency (EPA) or a State program authorized by the EPA under RCRA section 3006; required by orders authorized under RCRA; or required by orders authorized under RCRA section 7003.

(4) ~~Your site remediation is not subject to this subpart if the site remediation is conducted at a gasoline service station to clean up remediation material from a leaking underground storage tank.~~

(5) ~~Your site remediation is not subject to this subpart if the site remediation is conducted at a farm or residential site.~~

(6) Your site remediation is not subject to this subpart if the site remediation is conducted at a research and development facility that meets the requirements under Clean Air Act (CAA) section 112(c)(7).

(c) Your site remediation activities are not subject to the requirements of this subpart, except for the recordkeeping requirements in this paragraph, provided that you meet the requirements specified in paragraphs (c)(1) through (c)(3) of this section.

(1) You determine that the total quantity of the HAP listed in Table 1 to this subpart that is contained in the remediation material excavated, extracted, pumped, or otherwise removed during all of the site remediations conducted at your facility is less than 1 megagram (Mg) annually. This exemption applies the 1 Mg limit on a facility-wide, annual basis, and there is no restriction to the number of site remediations that can be conducted during this period.

(2) You must prepare and maintain at your facility written documentation to support your determination that the total HAP quantity in your remediation materials for the year is less than 1 Mg. The documentation must include a description of your methodology and data used for determining the total HAP content of the remediation material.

(3) Your Title V permit does not have to be reopened or revised solely to include the recordkeeping requirement specified in paragraph (c)(2) of this section. However, the requirement must be included in your permit the next time the permit is renewed, reopened, or revised for another reason.

(d) Your site remediation is not subject to the requirements of this subpart if all remediation activities at your facility subject to this subpart are completed and you have notified the Administrator in writing that all remediation activities subject to this subpart are completed. You must maintain records of compliance, in accordance with §63.7953, for each remediation activity that was subject to this subpart. All future remediation activity meeting the applicability criteria in this section must comply with the requirements of this subpart.

§ 63.7883 When do I have to comply with this subpart?

(a) If you have an existing affected source, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you no later than October 9, 2006.

(b) If you have a new affected source that manages remediation material other than a radioactive mixed waste as defined in §63.7957, then you must meet the compliance date specified in paragraph (b)(1) or (2) of this section, as applicable to your affected source.

(1) If the affected source's initial startup date is on or before October 8, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you by October 8, 2003.

(2) If the affected source's initial startup date is after October 8, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you upon initial startup.

(c) If you have a new affected source that manages remediation material that is a radioactive mixed waste as defined in §63.7957, then you must meet the compliance date specified in paragraph (c)(1) or (2) of this section, as applicable to your affected source.

(1) If the affected source's initial startup date is on or before October 8, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you no later than October 9, 2006.

(2) If the affected source's initial startup date is after October 8, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you upon initial startup.

(d) ~~If your facility is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP as defined in §63.2, then you must meet the compliance dates specified in paragraphs (d)(1) and (2) of this section.~~

~~(1) For each source at your facility that is a new affected source subject to this subpart, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you upon initial startup.~~

~~(2) For all other affected sources subject to this subpart, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you no later than 3 years after your facility becomes a major source.~~

(e) You must meet the notification requirements, according to the schedule applicable to your facility, as specified in §63.7950 and in 40 CFR part 63, subpart A. Some of the notifications must be submitted before you are required to comply with the emissions limitations and work practice standards in this subpart.

Section E.22

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b) ~~Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:~~

~~(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NOX) standards under this subpart.~~

~~(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are subject to the PM and NOx standards under this subpart and to the sulfur dioxide (SO2) standards under subpart D (§60.43).~~

~~(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NOXstandards under this subpart.~~

~~(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are also subject to the NOXstandards under this subpart and the PM and SO2standards under subpart D (§60.42 and §60.43).~~

(c) Affected facilities that also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the PM and NOXstandards under this subpart and the SO2 standards under subpart J (§60.104).

(d) ~~Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; §60.50) are subject to the NOXand PM standards under this subpart.~~

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).
(2) Section 60.44b(g).
(3) Section 60.49b(a)(4).

(h) ~~Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, or subpart AAAA of this part is not covered by this subpart.~~

(i) ~~Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart GG or KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)~~

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

(k) ~~Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.~~

§ 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration , also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.
Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO2control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is present as a gas at ISO conditions.

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m3 (70,000 Btu/hr-ft3).
ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m3 (70,000 Btu/hr-ft3) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical SO2emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO2emission control, has a SO2emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005, very low sulfur oil means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without SO2emission control, has a SO2emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this

contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

~~§ 60.42b - Standard for sulfur dioxide (SO2).~~

~~(a) Except as provided in paragraphs (b), (c), (d), or (k) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO2in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:~~

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

~~Where:~~
~~Es= SO2emission limit, in ng/J or lb/MMBtu heat input;~~
~~Ka= 520 ng/J (or 1.2 lb/MMBtu);~~
~~Kb= 340 ng/J (or 0.80 lb/MMBtu);~~
~~Ha= Heat input from the combustion of coal, in J (MMBtu); and~~
~~Hb= Heat input from the combustion of oil, in J (MMBtu).~~
~~Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.~~

~~(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO2in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO2emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable.~~

~~(c) On and after the date on which the performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO2emissions, shall cause to be discharged into the atmosphere any gases that contain SO2in excess of 50 percent of the potential SO2emission rate (50 percent reduction) and that contain SO2in excess of the emission limit determined according to the following formula:~~

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

~~Where:~~
~~Es= SO2emission limit, in ng/J or lb/MM Btu heat input;~~

~~Kc= 260 ng/J (or 0.60 lb/MMBtu);~~
~~Kd= 170 ng/J (or 0.40 lb/MMBtu);~~
~~Hc= Heat input from the combustion of coal, in J (MMBtu); and~~
~~Hd= Heat input from the combustion of oil, in J (MMBtu).~~
~~Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.~~

~~(d) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO2in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section.~~

~~(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;~~

~~(2) Affected facilities located in a noncontinental area; or~~

~~(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or~~
~~(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.~~

~~(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.~~

~~(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.~~

~~(g) Except as provided in paragraph (i) of this section and §60.45b(a), the SO2emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.~~

~~(h) Reductions in the potential SO2emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:~~
~~(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO2emissions and~~
~~(2) Emissions from the pretreated fuel (without combustion or post combustion SO2control) are equal to or less than the emission limits specified in paragraph (c) of this section.~~

~~(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO2control system is not being operated because of malfunction or maintenance of the SO2control system.~~

~~(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in §60.45b(c) or §60.45b(d), and following the monitoring procedures as described in §60.47b(a) or §60.47b(b) to determine SO2emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in §60.49b(r).~~

~~(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO2emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.~~

~~(2) Units firing only very low sulfur oil and/or a mixture of gaseous fuels with a potential SO2emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO2emissions limit in paragraph 60.42b(k)(1).~~

~~(3) Units that are located in a noncontinental area and that combust coal or oil shall not discharge any gases that contain SO2in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil.~~

~~(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO2emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.~~

~~§ 60.43b - Standard for particulate matter (PM).~~

~~(a) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:~~

~~(1) 22 ng/J (0.051 lb/MMBtu) heat input, (i) If the affected facility combusts only coal, or~~
~~(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.~~

~~(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.~~

~~(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and~~

~~(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,~~
~~(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,~~

~~(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and~~
~~(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.~~
~~(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO2emissions is not subject to the PM limits under §60.43b(a).~~

~~(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO2emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.~~

~~(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:~~

~~(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.~~

~~(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;~~

~~(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and~~

~~(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.~~

~~(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:~~

~~(1) 43 ng/J (0.10 lb/MMBtu) heat input;~~

~~(i) If the affected facility combusts only municipal-type solid waste; or~~

~~(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.~~

~~(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and~~

~~(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;~~

~~(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;~~

~~(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and~~

~~(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.~~

~~(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.~~

~~(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.~~

~~(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.~~

~~(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,~~

~~(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:~~

~~(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and~~
~~(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.~~

~~(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.~~

~~(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW~~

~~(250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.~~

~~(5) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.3 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO2or PM emissions is not subject to the PM limits under §60.43b(h)(1).~~

§ 60.44b Standard for nitrogen oxides (NOX).

(a) ~~Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOX(expressed as NO2) in excess of the following emission limits:~~

~~Fuel/steam generating unit type~~	~~Nitrogen oxide emission limits (expressed as NO_2) heat input~~	
	~~ng/J~~	~~lb/MMBTu~~
~~(1) Natural gas and distillate oil, except (4):~~		
~~(i) Low heat release rate~~	~~43~~	~~0.10~~
~~(ii) High heat release rate~~	~~86~~	~~0.20~~
~~(2) Residual oil:~~		
~~(i) Low heat release rate~~	~~130~~	~~0.30~~
~~(ii) High heat release rate~~	~~170~~	~~0.40~~
~~(3) Coal:~~		
~~(i) Mass-feed stoker~~	~~210~~	~~0.50~~
~~(ii) Spreader stoker and fluidized bed combustion~~	~~260~~	~~0.60~~
~~(iii) Pulverized coal~~	~~300~~	~~0.70~~
~~(iv) Lignite, except (v)~~	~~260~~	~~0.60~~
~~(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace~~	~~340~~	~~0.80~~
~~(vi) Coal-derived synthetic fuels~~	~~210~~	~~0.50~~
~~(4) Duct burner used in a combined cycle system:~~		
~~(i) Natural gas and distillate oil~~	~~86~~	~~0.20~~
~~(ii) Residual oil~~	~~170~~	~~0.40~~

(b) ~~Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever~~

~~date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOXin excess of a limit determined by the use of the following formula:~~

$$\cancel{E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}}$$

~~Where:~~
~~En= NOXemission limit (expressed as NO2), ng/J (lb/MMBtu);~~
~~ELgo= Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);~~
~~Hgo= Heat input from combustion of natural gas or distillate oil, J (MMBtu);~~
~~ELro= Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);~~
~~Hro= Heat input from combustion of residual oil, J (MMBtu);~~
~~ELc= Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and~~
~~Hc= Heat input from combustion of coal, J (MMBtu).~~

(c) ~~Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NOXin excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.~~

(d) ~~On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOXin excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas.~~

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NOXin excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:
En= NOX emission limit (expressed as NO2), ng/J (lb/MMBtu);

ELgo= Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);
Hgo= Heat input from combustion of natural gas, distillate oil and gaseous byproduct/waste, J (MMBtu);
ELro= Appropriate emission limit from paragraph (a)(2) for combustion of residual oil and/or byproduct/waste, ng/J (lb/MMBtu);
Hro= Heat input from combustion of residual oil, J (MMBtu);
ELc= Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and
Hc= Heat input from combustion of coal, J (MMBtu).

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NOX emission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NOX emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NOX emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in §60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NOX emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NOX emission limit will be established at the NOX emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NOX emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NOX limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) ~~Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NOX emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NOX emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NOX emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for~~

~~hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NOX emission limits of this section. The NOX emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NOX limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.~~

(h) For purposes of paragraph (i) of this section, the NOX standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) ~~Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:~~

~~(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;~~

~~(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and~~

~~(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.~~

(k) ~~Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NOX emission limits under this section.~~

(l) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOX(expressed as NO2) in excess of the following limits:
(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: A limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or
(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{gp}) + (0.20 \times H_r)}{(H_{gp} + H_r)}$$

Where:

En= NOX emission limit, (lb/MMBtu);
Hgo= 30-day heat input from combustion of natural gas or distillate oil; and
Hr= 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i) of subpart Da of this part, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

~~§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.~~

~~(a) The SO2emission standards under §60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil and complying with the fuel based limit under §60.42b(d) or §60.42b(k)(2) are allowed to exceed the limit 30 operating days per calendar year for by-product plant maintenance.~~

~~(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.~~

~~(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO2emission rate (% Ps) and the SO2emission rate (Es) pursuant to §60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.~~

~~(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO2standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.~~

~~(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:~~

~~(i) The procedures in Method 19 of appendix A of this part are used to determine the hourly SO2emission rate (Eho) and the 30-day average emission rate (Eao). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS) of §60.47b (a) or (b).~~
~~(ii) The percent of potential SO2emission rate (%Ps) emitted to the atmosphere is computed using the following formula:~~

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

~~Where:~~
~~%Ps= Potential SO2emission rate, percent;~~
~~%Rg= SO2removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and~~
~~%Rf= SO2removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.~~
~~(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:~~

~~(i) An adjusted hourly SO2emission rate (Ehoo) is used in Equation 19–19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate (Eaoo). The Eho° is computed using the following formula:~~

$$E_{ho}^{\circ} = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

~~Where:~~
~~Ehoo = Adjusted hourly SO2emission rate, ng/J (lb/MMBtu);~~
~~Eho= Hourly SO2emission rate, ng/J (lb/MMBtu);~~
~~Ew= SO2concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value Ewfor each fuel lot is used for each hourly average during the time that the lot is being combusted; and~~
~~Xk= Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.~~
~~(ii) To compute the percent of potential SO2emission rate (%Ps), an adjusted %Rg(%Rgo) is computed from the adjusted Eaoo from paragraph (b)(3)(i) of this section and an adjusted average SO2inlet rate~~
~~(Eaio) using the following formula:~~

$$\%R_g^{\circ} = 100\left(1.0 - \frac{E_{ao}^{\circ}}{E_{ai}^{\circ}}\right)$$

~~To compute Eaio , an adjusted hourly SO2inlet rate (Ehio) is used. The Ehio is computed using the following formula:~~

$$E_{hi}^{\circ} = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

~~Where:~~
~~Ehio = Adjusted hourly SO2inlet rate, ng/J (lb/MMBtu); and~~
~~Ehi= Hourly SO2inlet rate, ng/J (lb/MMBtu).~~

~~(4) The owner or operator of an affected facility subject to paragraph (b)(3) of this section does not have to measure parameters Ewor Xkif the owner or operator elects to assume that Xk= 1.0. Owners or operators of affected facilities who assume Xk= 1.0 shall:~~

~~(i) Determine %Psfollowing the procedures in paragraph (c)(2) of this section; and~~

~~(ii) Sulfur dioxide emissions (Es) are considered to be in compliance with SO2emission limits under §60.42b.~~

~~(5) The owner or operator of an affected facility that qualifies under the provisions of §60.42b(d) does not have to measure parameters Ewor Xkunder paragraph (b)(3) of this section if the owner or operator of the affected facility elects to measure SO2emission rates of the coal or oil following the fuel sampling and analysis procedures under Method 19 of appendix A of this part.~~

~~(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:~~

~~(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;~~

~~(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.~~

~~(e) The owner or operator of an affected facility subject to §60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.~~

~~(f) For the initial performance test required under §60.8, compliance with the SO2emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO2for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.~~

~~(g) After the initial performance test required under §60.8, compliance with the SO2emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO2for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for SO2are calculated to show compliance with the standard.~~

~~(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO2emissions data in calculating %Ps and Eho under paragraph (c), of this section whether or not the minimum emissions data requirements under §60.46b are achieved. All valid emissions data, including valid SO2emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating %Ps and Eho pursuant to paragraph (c) of this section.~~

~~(i) During periods of malfunction or maintenance of the SO2control systems when oil is combusted as provided under §60.42b(i), emission data are not used to calculate %Ps or Es under §60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under §60.42b(i).~~

~~(j) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).~~

~~(k) The owner or operator of an affected facility seeking to demonstrate compliance under §§60.42b(d)(4), 60.42b(j), and 60.42b(k)(2) shall follow the applicable procedures under §60.49b(r).~~

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NOX emission standards under §60.44b apply at all times.

(b) ~~Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.~~

(c) Compliance with the NOX emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) ~~To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:~~

~~(1) Method 3B of appendix A of this part is used for gas analysis when applying Method 5 or 17 of appendix A of this part.~~

~~(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:~~

~~(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and~~

~~(ii) Method 17 of appendix A of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (32 °F). The procedures of sections 2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A of this part after wet FGD systems if the effluent is saturated or laden with water droplets.~~

~~(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.~~

~~(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.~~

~~(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).~~

~~(5) For determination of PM emissions, the oxygen (O2) or CO2sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.~~

~~(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:~~

~~(i) The O2or CO2measurements and PM measurements obtained under this section;~~

~~(ii) The dry basis F factor; and~~

~~(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.~~

~~(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.~~

(e) To determine compliance with the emission limits for NOX required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for NOX under §60.48(b).

(1) For the initial compliance test, NOX from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NOX emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) ~~Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NOX emission standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NOX emission data for the preceding 30 steam generating unit operating days.~~

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NOX standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NOX emission data for the preceding 30 steam generating unit operating days.

(4) ~~Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NOX standards under §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NOX emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NOX emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NOX emission data for the preceding 30 steam generating unit operating days.~~

(5) ~~If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in §60.49b(e), the requirements of §60.48b(g)(1) apply and the provisions of §60.48b(g)(2) are inapplicable.~~

(f) ~~To determine compliance with the emissions limits for NOX required by §60.44b(a)(4) or §60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:~~

~~(1) The owner or operator of an affected facility shall conduct the performance test required under §60.8 as follows:~~

~~(i) The emissions rate (E) of NOX shall be computed using Equation 1 in this section:~~

$$\cancel{E = E_{sg} + \left(\frac{H_g}{H_b}\right)(E_{sg} - E_g) \qquad (Eq.1)}$$

~~Where:~~
~~E = Emissions rate of NOX from the duct burner, ng/J (lb/MMBtu) heat input;~~
~~Esg= Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;~~
~~Hg= Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);~~
~~Hb= Heat input rate to the duct burner, in J/hr (MMBtu/hr); and~~
~~Eg= Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.~~

~~(ii) Method 7E of appendix A of this part shall be used to determine the NOX concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O2concentration.~~

~~(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.~~

~~(iv) Compliance with the emissions limits under §60.44b(a)(4) or §60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or~~

~~(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under §60.48b for measuring NOXand O2and meet the requirements of §60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NOX emissions rate at the outlet from the steam generating unit shall constitute the NOX emissions rate from the duct burner of the combined cycle system.~~

(g) ~~The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method described in sections 5 and 7.3 of the ASME Power Test Codes 4.1 (incorporated by reference, see §60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of §60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of §60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.~~

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NOX emission standards under §60.44b using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NOX emission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods.

(i) ~~The owner or operator of an affected facility seeking to demonstrate compliance under paragraph §60.43b(h)(5) shall follow the applicable procedures under §60.49b(r).~~

(j) ~~In place of PM testing with EPA Reference Method 5, 5B, or 17 of appendix A of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 of appendix A of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(13) of this section.~~

~~(1) Notify the Administrator one month before starting use of the system.~~

~~(2) Notify the Administrator one month before stopping use of the system.~~

~~(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.~~

~~(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.~~

~~(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.~~

~~(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.~~

~~(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.~~

~~(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.~~
~~(ii) [Reserved]~~

~~(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.~~

~~(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(7) of this section are not met.~~

~~(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.~~

~~(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O2(or CO2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraphs (j)(7)(i) of this section.~~

~~(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.~~

~~(ii) For O2(or CO2), EPA reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.~~

~~(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.~~

~~(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.~~

~~§ 60.47b - Emission monitoring for sulfur dioxide.~~

~~(a) Except as provided in paragraphs (b), (f), and (h) of this section, the owner or operator of an affected facility subject to the SO2standards under §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO2concentrations and either O2or CO2concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO2and either O2or CO2concentrations shall both be monitored at the inlet and outlet of the SO2control device. If the owner or operator has installed and certified SO2and O2or CO2CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:~~

~~(1) When relative accuracy testing is conducted, SO2concentration data and CO2(or O2) data are collected simultaneously; and~~

~~(2) In addition to meeting the applicable SO2and CO2(or O2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and~~

~~(3) The reporting requirements of §60.49b are met. SO2and CO2(or O2) data used to meet the requirements of §60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO2data have been bias adjusted according to the procedures of part 75 of this chapter.~~

~~(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO2emissions and percent reduction by:~~

~~(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO2input rate, or~~

~~(2) Measuring SO2according to Method 6B of appendix A of this part at the inlet or outlet to the SO2control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO2and CO2measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.~~

~~(3) A daily SO2emission rate, ED, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A–8) and stated in ng/J (lb/MMBtu) heat input.~~

~~(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19–20 of Method 19 of appendix A of this part.~~

~~(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.~~

~~(d) The 1-hour average SO2emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average SO2emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to §60.13(h)(2). Hourly SO2emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.~~

~~(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.~~

~~(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.~~

~~(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.~~

~~(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO2CEMS at the inlet to the SO2control device is 125 percent of the maximum estimated hourly potential SO2emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO2control device is 50 percent of the maximum estimated hourly potential SO2emissions of the fuel combusted. Alternatively, SO2span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.~~

~~(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:~~

~~(i) For all required CO2and O2monitors and for SO2and NOX monitors with span values less than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to SO2and NOX span values less than 100 ppm;~~

~~(ii) For all required CO2and O2monitors and for SO2and NOX monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO2and NOX span values less than or equal to 30 ppm; and~~

~~(iii) For SO2, CO2, and O2monitoring systems and for NOX emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO2(regardless of the SO2emission level during the RATA), and for NOX when the average NOX emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.~~

~~(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under §60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in §60.49b(r).~~

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) ~~Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a CEMS for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.~~

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NOX standard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NOX and O2(or CO2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NOX emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.
(d) The 1-hour average NOX emission rates measured by the continuous NOX monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) ~~For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a continuous monitoring system for measuring opacity shall be between 60 and 80 percent.~~

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NOXis determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NOXspan values shall be determined as follows:

Fuel	Span values for NO_X (ppm)
Natural gas	500.
Oil	500.
Coal	1,000.
Mixtures	500 (x + y) + 1,000z.

Where:
x = Fraction of total heat input derived from natural gas;
y = Fraction of total heat input derived from oil; and
z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NOX span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph

(e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NOX emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) ~~The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, or any mixture of these fuels, greater than 10 percent (0.10) shall:~~

~~(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or~~

~~(2) Monitor steam generating unit operating conditions and predict NOX emission rates as specified in a plan submitted pursuant to §60.49b(c).~~

(h) ~~The owner or operator of a duct burner, as described in §60.41b, that is subject to the NOX standards of §60.44b(a)(4) or §60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NOX emissions.~~

(i) ~~The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a CEMS for measuring NOX emissions.~~

(j) ~~The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), or (5) of this section is not required to install or operate a COMS for measuring opacity if:~~

~~(1) The affected facility uses a PM CEMS to monitor PM emissions; or~~

~~(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO2or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under §60.49b(r); or~~

~~(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO2or PM emissions; or~~

~~(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section.~~

~~(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.~~

~~(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in~~

~~§60.58b(i)(3) of subpart Eb of this part.~~

~~(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).~~

~~(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.~~

~~(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.~~
~~(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.~~

~~(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.~~
~~(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.~~

~~(5) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the appropriate delegated permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.~~

(k) ~~Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a CEMS, and record the output of the system, for PM emissions discharged to the atmosphere as specified in §60.46b(j). The CEMS specified in paragraph §60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.~~

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4) ~~Notification that an emerging technology will be used for controlling emissions of SO2. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42b(a) unless and until this determination is made by the Administrator.~~

(b) The owner or operator of each affected facility subject to the SO2, PM, and/or NOX emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NOX standard of §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under §60.48b(g)(2) and the records to be maintained under §60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NOX emission rates (i.e., ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e. , the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e. , flue gas O2level);

(2) Include the data and information that the owner or operator used to identify the relationship between NOX emission rates and these operating conditions; and
(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(j).

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(e) ~~For an affected facility that combusts residual oil and meets the criteria under §§60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see §60.17), or fuel suppliers. If residual oil blends are being~~

~~combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.~~

(f) ~~For facilities subject to the opacity standard under §60.43b, the owner or operator shall maintain records of opacity.~~

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NOX standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NOX emission rates (expressed as NO2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NOX emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NOX emission rates are in excess of the NOX emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards under §60.43b(e) or to the operating parameter monitoring requirements under §60.13(i)(1).

(2) Any affected facility that is subject to the NOX standard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NOX emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NOx emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NOX under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) ~~The owner or operator of any affected facility subject to the SO2standards under §60.42b shall submit reports.~~

(k) ~~For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:~~

~~(1) Calendar dates covered in the reporting period;~~

~~(2) Each 30-day average SO2emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;~~
~~(3) Each 30-day average percent reduction in SO2emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;~~

~~(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO2or diluent (O2or CO2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;~~

~~(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;~~

~~(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;~~

~~(7) Identification of times when hourly averages have been obtained based on manual sampling methods;~~

~~(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;~~

~~(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;~~

~~(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and~~

~~(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.~~

(l) ~~For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:~~

~~(1) Calendar dates when the facility was in operation during the reporting period;~~

~~(2) The 24-hour average SO2emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;~~

~~(3) Identification of the steam generating unit operating days that coal or oil was combusted for which S02or diluent (O2or CO2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;~~

~~(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;~~

~~(5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;~~

~~(6) Identification of times when hourly averages have been obtained based on manual sampling methods;~~

~~(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;~~

~~(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and~~

~~(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§60.47b(e)(4)(i) through (e)(4)(iii).~~

(m) ~~For each affected facility subject to the SO2standards under §60.42(b) for which the minimum amount of data required under §60.47b(f) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:~~

~~(1) The number of hourly averages available for outlet emission rates and inlet emission rates;~~

~~(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;~~

~~(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and~~

~~(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.~~

(n) ~~If a percent removal efficiency by fuel pretreatment (i.e. , %Rf) is used to determine the overall percent reduction (i.e. , %Ro) under §60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.~~

~~(1) Indicating what removal efficiency by fuel pretreatment (i.e. , %Rf) was credited during the reporting period;~~

~~(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;~~

~~(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and~~

~~(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.~~

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) ~~The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:~~

~~(1) Calendar date;~~

~~(2) The number of hours of operation; and~~

~~(3) A record of the hourly steam load.~~

(q) ~~The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:~~

~~(1) The annual capacity factor over the previous 12 months;~~

~~(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and~~

~~(3) If the affected facility meets the criteria described in §60.44b(j), the results of any NOX emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NOX emission test.~~

(r) ~~The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:~~

~~(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) or §60.42b(k)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur~~

~~oil meeting this definition and/or pipeline quality natural gas was combusted in the affected facility during the reporting period; or~~

~~(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:~~

~~(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;~~

~~(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For~~
~~distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;~~

~~(iii) The ratio of different fuels in the mixture; and~~

~~(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.~~

(s) ~~Facility specific NOX standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:~~

~~(1) Definitions .~~
~~Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.~~
~~Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.~~
~~Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.~~

~~(2) Standard for nitrogen oxides . (i) When fossil fuel alone is combusted, the NOXemission limit for fossil fuel in §60.44b(a) applies.~~

~~(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NOX emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.~~

~~(3) Emission monitoring . (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.~~

~~(ii) The NOX emission limit shall be determined by the compliance and performance test methods and procedures for NOX in §60.46b(i).~~

~~(iii) The monitoring of the NOX emission limit shall be performed in accordance with §60.48b.~~

~~(4) Reporting and recordkeeping requirements . (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.~~
~~(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.~~

~~(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.~~

(t) ~~Facility-specific NOX standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:~~

~~(1) Definitions .~~
~~Air ratio control damper is defined as the part of the low NOX burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.~~
~~Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.~~

~~(2) Standard for nitrogen oxides . (i) When fossil fuel alone is combusted, the NOX emission limit for fossil fuel in §60.44b(a) applies.~~

~~(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NOX emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.~~

~~(3) Emission monitoring for nitrogen oxides . (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.~~

~~(ii) The NOX emission limit shall be determined by the compliance and performance test methods and procedures for NOXin §60.46b.~~

~~(iii) The monitoring of the NOX emission limit shall be performed in accordance with §60.48b.~~

~~(4) Reporting and recordkeeping requirements . (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).~~

~~(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.~~

~~(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of §60.49b.~~

(u) ~~Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia . (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (“site”) and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).~~

~~(i) The site shall equip the natural gas-fired boilers with low NOX technology.~~

~~(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NOX emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.~~

~~(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.~~

~~(2) [Reserved]~~

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO2and/or NOX and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) ~~Facility-specific NOX standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:~~
~~(1) Standard for nitrogen oxides . (i) When fossil fuel alone is combusted, the NOXemission limit for fossil fuel in §60.44b(a) applies.~~

~~(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NOX emission limit is 215 ng/J (0.5 lb/MMBtu).~~

~~(2) Emission monitoring for nitrogen oxides . (i) The NOX emissions shall be determined by the compliance and performance test methods and procedures for NOX in §60.46b.~~

~~(ii) The monitoring of the NOX emissions shall be performed in accordance with §60.48b.~~

~~(3) Reporting and recordkeeping requirements . (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).~~

~~(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.~~

~~(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.~~

(y) ~~Facility-specific NOX standard for INEOS USA's AOGI located in Lima, Ohio:~~

~~(1) Standard for NOX. (i) When fossil fuel alone is combusted, the NOXemission limit for fossil fuel in §60.44b(a) applies.~~

~~(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NOX emission limit is 645 ng/J (1.5 lb/MMBtu).~~

~~(2) Emission monitoring for NOX. (i) The NOX emissions shall be determined by the compliance and performance test methods and procedures for NOX in §60.46b.~~

~~(ii) The monitoring of the NOX emissions shall be performed in accordance with §60.48b.~~

~~(3) Reporting and recordkeeping requirements . (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.~~

~~(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.~~

~~(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.~~

Section E.23

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(d) ~~Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the Federal Aid Highway System may petition the Administrator for approval to use any fuels mixed with used lubricating oil that do not meet the fuel requirements of paragraphs (a) and (b) of this section. Owners and operators must demonstrate in their petition to the Administrator that there is no other place to use the lubricating oil. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.~~

(e) ~~Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.~~

~~Table 6 to Subpart IIII of Part 60.—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]~~

~~Mode No.~~	~~Engine speed[1]~~	~~Torque (percent)[2]~~	~~Weighting factors~~
~~1~~	~~Rated~~	~~100~~	~~0.30~~
~~2~~	~~Rated~~	~~75~~	~~0.50~~
~~3~~	~~Rated~~	~~50~~	~~0.20~~

~~[1]Engine speed: ±2 percent of point.~~

[2]~~Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.~~

~~Table 7 to Subpart IIII of Part 60.—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder~~

~~[As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]~~

~~For each~~	~~Complying with the requirement to~~	~~You must~~	~~Using~~	~~According to the following requirements~~
~~1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder~~	~~a. Reduce NO_xemissions by 90 percent or more~~	~~i. Select the sampling port location and the number of traverse points;~~	~~(1) Method 1 or 1A of 40 CFR part 60, appendix A~~	~~(a) Sampling sites must be located at the inlet and outlet of the control device.~~
~~–~~		~~ii. Measure O_2at the inlet and outlet of the control device;~~	~~(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A~~	~~(b) Measurements to determine O_2concentration must be made at the same time as the measurements for NO_xconcentration.~~
~~–~~		~~iii. If necessary, measure moisture content at the inlet and outlet of the control device; and,~~	~~(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)~~	~~(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_xconcentration.~~
~~–~~		~~iv. Measure NO_xat the inlet and outlet of the control device~~	~~(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)~~	~~(d) NO_xconcentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.~~
~~–~~	~~b. Limit the concentration of NO_xin the stationary CI internal~~	~~i. Select the sampling port location and the number of traverse points;~~	~~(1) Method 1 or 1A of 40 CFR part 60, Appendix A~~	~~(a) If using a control device, the sampling site must be located at the outlet of the control device.~~

~~For each~~	~~Complying with the requirement to~~	~~You must~~	~~Using~~	~~According to the following requirements~~
	~~combustion engine exhaust.~~			
–		~~ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location; and,~~	~~(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A~~	~~(b) Measurements to determine O_2concentration must be made at the same time as the measurement for NO_xconcentration.~~
–		~~iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,~~	~~(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)~~	~~(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_xconcentration.~~
–		~~iv. Measure NO_xat the exhaust of the stationary internal combustion engine~~	~~(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)~~	~~(d) NO_xconcentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.~~
–	~~c. Reduce PM emissions by 60 percent or more~~	~~i. Select the sampling port location and the number of traverse points;~~	~~(1) Method 1 or 1A of 40 CFR part 60, appendix A~~	~~(a) Sampling sites must be located at the inlet and outlet of the control device.~~
–		~~ii. Measure O_2at the inlet and outlet of the control device;~~	~~(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A~~	~~(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.~~
–		~~iii. If necessary, measure moisture content at the inlet and outlet of the control device; and~~	~~(3) Method 4 of 40 CFR part 60, appendix A~~	~~(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM~~

~~For each~~	~~Complying with the requirement to~~	~~You must~~	~~Using~~	~~According to the following requirements~~
				~~concentration.~~
–		~~iv. Measure PM at the inlet and outlet of the control device~~	~~(4) Method 5 of 40 CFR part 60, appendix A~~	~~(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.~~
–	~~d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust~~	~~i. Select the sampling port location and the number of traverse points;~~	~~(1) Method 1 or 1A of 40 CFR part 60, Appendix A~~	~~(a) If using a control device, the sampling site must be located at the outlet of the control device.~~
–		~~ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location; and~~	~~(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A~~	~~(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.~~
–		~~iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and~~	~~(3) Method 4 of 40 CFR part 60, appendix A~~	~~(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.~~
–		~~iv. Measure PM at the exhaust of the stationary internal combustion engine~~	~~(4) Method 5 of 40 CFR part 60, appendix A~~	~~(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.~~

Section E.24:

§ 63.2334 Am I subject to this subpart?
(a) Except as provided for in paragraphs (b) and (c) of this section, you are subject to this subpart if you own or operate an OLD operation that is located at, or is part of, a major source of HAP emissions. An OLD operation may occupy an entire plant site or be collocated with other industrial (*e.g.,* manufacturing) operations at the same plant site.
(b) Organic liquid distribution operations located at research and development facilities, consistent with section 112(c)(7) of the Clean Air Act (CAA), are not subject to this subpart.

(c) ~~Organic liquid distribution operations do not include the activities and equipment, including product loading racks, used to process, store, or transfer organic liquids at facilities listed in paragraph (c) (1) and (2) of this section.~~
~~(1) Oil and natural gas production field facilities, as the term "facility" is defined in §63.761 of subpart HH.~~
~~(2) Natural gas transmission and storage facilities, as the term "facility" is defined in §63.1271 of subpart HHH.~~

§ 63.2342 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to the schedule identified in paragraph (a)(1), (a)(2), or (a)(3) of this section, as applicable.

(1)~~(i) Except as provided in paragraph (a)(1)(ii) of this section, if you startup your new affected source on or before February 3, 2004 or if you reconstruct your affected source on or before February 3, 2004, you must comply with the emission limitations, operating limits, and work practice standards for new and reconstructed sources in this subpart no later than February 3, 2004.~~

~~(ii) For any emission source listed in paragraph §63.2338(b) at an affected source that commenced construction or reconstruction after April 2, 2002, but before February 3, 2004, that is required to be controlled based on the applicability criteria in this subpart, but:~~

~~(A) Would not have been required to be controlled based on the applicability criteria as proposed for this subpart, you must comply with the emission limitations, operating limits, and work practice standards for each such emission source based on the schedule found in paragraph (b) of this section or at startup, whichever is later; or~~

~~(B) Would have been subject to a less stringent degree of control requirement as proposed for this subpart, you must comply with the emission limitations, operating limits, and work practice standards in this subpart for each such emission source based on the schedule found in paragraph (b) of this section or at startup, whichever is later, and if you start up your affected new or reconstructed source before February 5, 2007, you must comply with the emission limitations, operating limits, and work practice standards for each such emission source as proposed for this subpart, until you are required to comply with the emission limitations, operating limits, and work practice standards in this subpart for each such emission source based on the schedule found in paragraph (b) of this section.~~

(c) ~~If you have an area source that does not commence reconstruction but increases its emissions or its potential to emit such that it becomes a major source of HAP emissions and an existing affected source subject to this subpart, you must be in compliance by 3 years after the area source becomes a major source.~~

(d) You must meet the notification requirements in §§63.2343 and 63.2382(a), as applicable, according to the schedules in §63.2382(a) and (b)(1) through (3) and in subpart A of this part. Some of these notifications must be submitted before the compliance dates for the emission limitations, operating limits, and work practice standards in this subpart.

<u>Section E.26</u>:

§ 60.480a Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in §60.481a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in §60.486a(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in §60.489 is exempt from §§60.482–1a through 60.482–11a.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§60.482–1a through 60.482–11a.

(4) ~~Any affected facility that produces beverage alcohol is exempt from §§60.482–1a through 60.482–11a.~~

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§60.482–1a through 60.482–11a.

EPA Comment No. 5:

Some of the specific unit name descriptions provided in the draft permits vary from the unit names used in regulations included in the current SIP as well as the recently submitted SIP revision. For clarity, IDEM should cross-reference the SIP and permit unit descriptions where the two differ.

Response:

IDEM has cross-referenced the SIP and the permit unit descriptions and added clarifications to the descriptions of emissions units subject to the SIP as appropriate (for example, in Condition D.1.1.1, the No. 11 pipe still which includes both 11A and 11C pipe stills have been identified as "No. 11 pipe still (including nos. 11A and 11C pipe still)" for clarification purposes.

EPA Comment No. 6:

On January 25, 2007, and November 29, 2007, EPA issued separate Notices of Violation (NOVs) to BP. In some instances, the violations alleged in EPA's NOVs also constitute alleged violations of the Consent Decree between the United States, et al., and BP entered on August 29, 2001. Because BP is allegedly not in compliance with all applicable Clean Air Act requirements, IDEM cannot issue a Title V permit to BP that serves as a shield to alleged violations. IDEM must include language appropriately limiting the application of the permit shield set out in 42 U.S.C. Section 7661(c)(f) and 40 CFR Part

70.6. EPA will continue to seek resolution of all violations. Our review of BP's draft permit and any enforcement actions are necessarily separate matters, and EPA may take actions as appropriate.

Response:

IDEM received the BP OCC project application on November 1, 2007 and a completeness determination regarding the application was made by IDEM on November 19, 2007, ten days prior to the violations identified in the November 29, 2007 Notice of Violation issued by the U.S. EPA to BP.

The alleged violations of the sulfur dioxide and reduced sulfur compound emission limits at the sulfur recovery plant were intermittent and BP contends were the result of malfunctions and occurred prior to the effective date of BP's initial Title V permit which was January 1, 2007. The OCC project includes the installation of redundant equipment which will automatically address the prior malfunction problems that led to the alleged violations at the sulfur recovery plant. This redundant equipment should also address any potential exceedance of the hydrogen sulfide limit due to flaring. Because the past alleged violations were intermittent and because the cause of these emission limit exceedances will be addressed by the OCC project, IDEM contends that a schedule of compliance is not necessary for the past alleged violations of sulfur dioxide and reduced sulfur compounds limit. Further, the U.S. EPA is not prohibited from pursuing civil enforcement concerning these alleged past violations because they are not included within the permit shield provisions of the Title V permit.

The alleged violations for failure to conduct performance testing and submit results pursuant to the Refinery MACT II concern timing issues. BP has completed performance testing and submitted results of its HCl emissions from Ultraformers 3 and 4 as required by the Refinery MACT II therefore a compliance schedule is not indicated. Also, the U.S. EPA is not prohibited from pursuing civil enforcement concerning the alleged past violation of the Refinery MACT II because it is not included within the permit shield provision of the Title V permit.

IDEM has developed and U.S. EPA Region V has approved placeholder language that effectively serves the purpose of a compliance schedule as contemplated by Title V of the Clean Air Act. This language has been used in Title V permits previously when major New Source Review violation allegations have not been resolved to the point where a meaningful compliance schedule can be established and inserted into the Title V permit. For the record, IDEM would point out that it disagrees with and is not bound by the position taken by the United States Second Circuit Court of Appeals in *NYPIRG v. Johnson* that it is reasonable to require that a traditional compliance schedule be placed in a Title V permit prior to an adjudication or settlement in cases involving major New Source Review allegations because of the myriad economic and technical decisions involved in establishing a remedy if one is indicated. The placeholder language will address the concerns that were actually contemplated by the Title V compliance schedule requirement, that is, to fulfill the reason that Congress created the Title V program: "To allow the public and government officials to know whether facilities covered by the program are complying with Clean Air Act-based air pollution limitations and standards." *See* January 18, 2000 letter to Carol Browner, U.S. EPA Administrator from various national and regional organizations, http://www.titlev.org/News%20Release/SignOn70.pdf

If it is determined that major New Source Review violations have occurred then IDEM will reopen and revise the permit to include BACT, LAER, NSPS or NESHAP emission limits and milestones for achieving compliance. In the mean time the BP permit language will make clear that no permit shield will attach to the units with alleged NSPS or major New Source Review violations.
As a result of this comment and in keeping with IDEM the following condition has been modified as follows:

B.12 Permit Shield [326 IAC 2-7-15] [326 IAC 2-7-20] [326 IAC 2-7-12]

(a) Pursuant to 326 IAC 2-7-15, the Permittee has been granted a permit shield. The permit shield provides**, except as otherwise specified in this Section (B.12 - Permit Shield),** that compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the effective date of the permit, provided that either the applicable requirements are included and specifically identified in this permit or the permit contains an explicit determination or concise summary of a determination that other specifically identified requirements are not applicable. The Indiana statutes from IC 13 and rules from 326 IAC, referenced in conditions in this permit, are those applicable at the time the permit was issued. The issuance or possession of this permit shall not alone constitute a defense against an alleged violation of any law, regulation or standard, except for the requirement to obtain a Part 70 permit under 326 IAC 2-7 or for applicable requirements for which a permit shield has been granted.

This permit shield does not extend to applicable requirements which are promulgated after the date of issuance of this permit unless this permit has been modified to reflect such new requirements.

…

(h) On January 25, 2007 and November 29, 2007 the U.S. EPA issued Notices of Violation (NOV) to the Permittee for allegedly failing to comply with the provisions set out in 326 IAC 2 and the Clean Air Act, including the Prevention of Significant Deterioration and the nonattainment New Source Review programs, the federal New Source Performance Standards (NSPS), and the National Emission Standards for Hazardous Air Pollutants. In addition, the Notices of Violation issued by U.S.EPA allege violations of the Consent Decree between the United States, et al., and BP entered on August 29, 2001, and amendments thereto. Therefore the Permit Shield in Section B - Permit Shield does not shield the Permittee from possible enforcement actions initiated by U.S. EPA, IDEM or citizens. Compliance with the terms of this permit does not serve as proof of compliance for the emission units or the matters addressed in the NOVs. Following resolution of this enforcement action, IDEM will reopen this permit, if necessary, to incorporate a compliance schedule or any new applicable requirements. The standard language of Section B - Permit Shield does not shield any activity on which the permit is silent.

IDEM, OAQ Changes

IDEM Change No. 1:

Upon further review, IDEM, OAQ has determined that the NOx emissions from FCU 500 and FCU 600 should be calculated based on NO2 instead of NOx in the following equation used in Appendix C of the Technical Support Document:

NOx emissions [tpy] =
coke burn rate [1000 lb coke/yr] * {NOx concentration [ppm @ 0% O2] / 1E6} * 11.6 [lb flue gas per lb coke burned] * Molecular Weight of NOx [lb/lb-mole]/ 31 [Molecular Weight of flue gas in lb/lb-mole] / 2000 [lb/ton]

Using the molecular weight of NO2 (i.e., 46 lb/lb-mole) in this equation, changes to the estimate of baseline and future project emissions would occur for NOx emissions for FCU 500 and FCU 600. BP has proposed a NOx future allowable emissions limitation for FCU 500 of 228.6 tpy NOx using a lower NOx concentration of 39.7 ppm instead of 40 ppm included in the original calculations. The NOx future allowable emissions limitation for FCU 600 has also been updated to 73.8 based on the updated methodology. The updated tables are included as Appendix C and E of this Addendum to the Technical Support Document.

Conditions D.21.3 and D.22.3 have been updated as follows:

D.21.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for FCU 500 after the start-up of the new Coker (#2 Coker):

(a) The emissions of NOx shall not exceed ~~155.3~~ **228.6** tons per 12 consecutive month period, with compliance determined at the end of each month.

(b) The emissions of VOC shall not exceed 3.3 pounds per 1000 barrels of fresh feed used per 12 consecutive month period, with compliance determined at the end of each month.

(c) The emissions of SO2 shall not exceed 200.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) The emissions of PM and PM-10 shall not exceed 0.465 pounds per 1000 pounds of coke burned at FCU 500 per 12 consecutive month period, with compliance determined at the end of each month.

(e) The emissions of CO shall not exceed 147.2 tons per 12 consecutive month period, with compliance determined at the end of each month.

(f) The fresh feed used at FCU 500 shall not exceed 37.6 million barrels per 12 consecutive month period, with compliance determined at the end of each month.

(g) The coke burned at FCU 500 shall not exceed 669,191,000 pounds per 12 consecutive month period, with compliance determined at the end of each month.

(h) The FCU 500 blowdown stack shall be permanently shutdown and the pressure relief discharges that were routed to the blowdown stack will be routed to the VRU flare.

Compliance with the FCU 500 throughput limits and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, CO, SO2, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.22.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for FCU 600:

After the startup of the New Coker (#2 Coker), the Permittee shall comply with the following:

(a) The emissions of NOx shall not exceed ~~49.7~~ **73.8** tons per 12 consecutive month period, with compliance determined at the end of each month.

(b) The emissions of VOC shall not exceed 3.3 pounds per 1000 barrels of fresh feed used per 12 consecutive month period, with compliance determined at the end of each month.

(c) The emissions of SO2 shall not exceed 190.0 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) The emissions of PM and PM-10 shall not exceed 0.35 pounds per 1000 pounds of coke burned at FCU 600 per 12 consecutive month period, with compliance determined at the end of each month.

(e) The emissions of CO shall not exceed 92.1 tons per 12 consecutive month period, with compliance determined at the end of each month.

(f) The fresh feed used at FCU 600 shall not exceed 24.09 million barrels per 12 consecutive month period, with compliance determined at the end of each month.

(g) The coke burned at FCU 600 shall not exceed 428,802,000 pounds per 12 consecutive month period, with compliance determined at the end of each month.

(h) The FCU 600 blowdown stack shall be permanently shutdown and with the exhaust routed to the FCU stack.

Compliance with the FCU 600 throughput limits and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

IDEM Change No. 2:

Throughout the permit there are units affected by the CXHO project that will be subject to new emission limitations. These limits are necessary to ensure that the net emission increases or decreases remain below the significant levels under PSD, EO, and nonattainment NSR. For these affected units, which are not new or modified, the limits will be effective upon issuance of the Significant Permit Modification (SPM No. 089-25488-00453). To ensure that this is clear to BP and the public, IDEM has amended conditions D.9.3, D.10.3, D.11.3, D.16.3, D.17.3, D.18.3, D.19.3, and D.20.3 to reflect the effective date of these limits.

IDEM Change No. 3:

Throughout the permit there are references to the phased netting approach originally proposed for this project. With the inclusion of section D.0, which requires monitoring and recordkeeping to ensure that the project remains below the significant levels for PSD, EO, and nonattianment NSR, these references are no longer necessary for each D section. Therefore, the phrase “at each stage of the phased construction of the CXHO project” has been removed from these D sections.

Comments from BP Products North America, Inc. - Whiting Business Unit

OAQ received comments from BP Products North America, Inc. - Whiting Business Unit, Whiting, Indiana. The summary of the comments and IDEM, OAQ responses, including changes to the permit (language deleted is shown in strikeout and language added is shown in **bold**) are as follows:

BP comment 1:

Some of the emission unit descriptions in the D sections do not match the descriptions in Section A.2 of the permit.

Response:

Section A.3 has been modified to update the unit descriptions as follows:

A.3 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(15)]

This stationary source consists of the following emission units and pollution control devices:

(a) Nos. 11A and 11C Pipe Stills built in 1956, with a rated capacity of 220,800 barrels per day, and identified as Unit ID 120 process crude into various hydrocarbon fractions based on boiling points. This facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) ... (7)

(8) ~~No. 11A PS and No. 11C PS WARP, permitted in 2008, to replace the two existing blowdown stacks identified as stacks 11PS-A and 11PS-C, with the exhaust being re-routed to the DDU flare.~~
As part of the No. 11A PS and No. 11C PS WARP, per SPM 089-25488-00453, the two existing blowdown stacks identified as stacks 11PS-A and 11PS-C will be shutdown, with the emergency pressure relief discharge that was previously routed to the blowdown stacks being re-routed to the DDU flare, except for T-300 vacuum tower relief discharge and the COVs.

(b) No. 11B Coker, which processes heavy crude fractions into coke, and Coke Pile. These facilities are identified as Unit 120 and are rated at 2,000 tons of coke per day. The facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) Four (4) process heaters comprising:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-101 H-102 H-103 H-104	200 (total)	120-04	None

(2) Storage and handling of the bulk material. Fugitive emissions are controlled by keeping the coke wetted and having a 15' sheet piling wall surrounding the coke pile. The coke pile height will not exceed 15'.

(3) The No. 11B Coker is connected to the DDU flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges and other connectors.

(Note: The No. 11B Coker and **Coke Handling System** ~~Pile~~, heaters H-101, H-102, H-103, and H-104 will be replaced by the New Coker (#2 Coker) and Coke Pile and heaters H-201, H-202, and H-203 as part of the CXHO project, identified later in this section).

New Coker (#2 Coker), constructed as part of CXHO project, which processes heavy crude fractions into coke, and new Coke Handling System. These facilities are identified as Unit 800 and are rated at 6,000 tons of coke per day. The New Coker (#2 Coker) heaters H-201, H-202, and H-203 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New Coker (#2 Coker) heater stacks have continuous emissions monitors (CEMS) for NOx and CO. The existing Coker and Coke Pile will be replaced as part of the CXHO Project. The facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) Process heaters comprising of:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted to	Emission Controls
H-201	208	800-01	Low-NO_X burners and selective catalytic reduction
H-202	208	800-02	Low-NO_X burners and selective catalytic reduction
H-203	208	800-03	Low-NO_X burners and selective catalytic reduction

(2) ~~Storage and handling (including transfer points 1 through 10) of the bulk material comprised of a partially enclosed crusher, enclosed conveyors, enclosed storage, day bins, and rail car load out. In order to minimize fugitive emissions from the coke handling process, transfer points 1 and 10 will include enclosed conveyors and transfer points 2 through 9 will use enclosed buildings, and all transfer points are controlled by water sprays.~~ **Storage and handling (including up to 10 transfer points) of the bulk material comprised of a partially enclosed crusher, enclosed conveyors, enclosed storage, day bins, and rail car load out under the main operating scenario. In order to minimize fugitive emissions from the coke handling process, transfer points 1 and 10 will include enclosed conveyors and transfer points 2 through 9 will use enclosed buildings, and water sprays. Coke handling operations will be expected to operate under this main operating scenario for at least 95% of operating hours annually. There will also be an alternative operating scenario which will consist of three enclosed conveyors with unenclosed transfer points. Coke**

handling operations are expected to operate under this alternate operating scenario for no more than 5% of operating hours annually.

(3) The Coker is connected to the South flare system (included in Section D.35). The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) One (1) storage tank, identified as TK-6255, with a maximum storage capacity of 14,028,000 gallons storing coker resid at a vapor pressure less than 0.5 psia. Tank TK-6255 is equipped with a fixed roof.

(5) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the CXHO Project, which processes crude into various hydrocarbon fractions based on boiling points, identified as Unit ID 130, and is rated at 336,000 barrels per day. Heaters identified as H-1AN, H-1AS, H-1B, H-2, H-1CN, ~~H-1CS~~, and H-1CX will be shutdown and replaced by heaters H-101A, H-101B, and H-102 as part of the CXHO project. The facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) The following process heaters, all of which are fired by natural gas, refinery gas, or liquified petroleum gas:

Heater Identification	Construction Date/Permitted Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-1AN	1959	121.5	130-01	None
H-1AS	1959	121.5	130-01	None
H-1B	1959	243	130-01	None
H-2	1959	174	130-01	Ultra low NO_x burners
H-1CN	1995	120	130-02	Low NO_x burners
H-1CS	1967	a	b	None
H-1CX	1977	410	130-04	Low NO_x burners
H-101A	Permitted in 2008 **(SPM 089-25488-00453)**	355	130-05	Ultra low NOx Burners
H-101B	Permitted in 2008 **(SPM 089-25488-00453)**	355	130-07	Ultra low NOx Burners
H-102	Permitted in 2008 **(SPM 089-25488-00453)**	331	130-06	Ultra low NOx Burners

[a] No longer in service -- was rated at 120 MMBtu/hour.
[b] No longer in service -- was exhausted to stack 130-03.

(d) The Sulfur Recovery Unit (SRU) Facility, identified as Unit ID 162, originally constructed in 1971 and expanded in 1981 and 1995, and rated at 600 long tons per day, to be modified as part of the CXHO Project, increasing the capacity to 1,300 long tons per day of sulfur. The facility includes the following and may also include insignificant activities listed in Section A.4 of this permit:

(1) ... (11)

(12) One (1) modular degassing unit, which removes gases that are emitted during the cooling of molten sulfur. Removed gases are vented to the SBS TGU. **Removed gases will be vented to the front-end of Claus Trains D and/or E as part of the CXHO project.**

(13) Two (2) modular degassing units, to be installed as part of the CXHO project, which remove gases that are emitted during the cooling of molten sulfur. The gases will be vented to the front-end of Claus Trains D and/or E as part of the CXHO project.

(14) Three (3) sulfur pits, (Sulfur Pits A, B, and C) used to store molten sulfur with their vent stacks routed to the B/S TGU and/or the SBS. As part of the CXHO project, the vents from the sulfur pits A, B and C will be routed to either COT1 and/or COT2.

(15) Two (2) sulfur pits (Sulfur Pits D and E), to be installed as part of the CXHO project, used to store molten sulfur and the vents routed to either COT1 and/or COT2.

(16) One (1) sour water storage tank, identified as TK-431, having a maximum storage capacity of 845,600 gallons and equipped with an external floating roof. The maximum true vapor pressure of the material stored in this tank is less than 0.5 psia.

(17) One (1) sour water storage tank, identified as TK-410, permitted in 2006, having a maximum storage capacity of 4,351,200 gallons and equipped with an external floating roof. The maximum true vapor pressure of the material stored in this tank is less than 0.5 psia.

(~~17~~ **18**) Two (2) Claus Offgas Treaters (COT), identified as COT1 and COT2, to be installed as part of the CXHO project, thermal oxidation systems which combust natural gas, each rated at 72 mmBTU/hr, exhausting at stacks S/V 162-06 and 162-07.

(~~18~~ **19**) Two (2) sulfur storage tanks, identified as SH-1 and SH-2, each with a maximum storage capacity of 1,008,000 gallons and used to store molten sulfur exhausting to stacks S/V 163-09 and 162-10. These tanks will be constructed as part of the CXHO Project and are both fixed roof tanks controlled by a caustic scrubber.

(e) (1) Vapor Recovery Unit 100 (VRU-100) identified as Unit ID 241, and Vapor Recovery Unit 200 (VRU-200) identified as Unit ID 231, permitted for turnaround (SPM 089-25488-00453), to repair or replace tower trays and increase existing pumping and cooling capacities. Gasoline and lighter products from the FCUs are separated in the VRUs using a series of distillation towers. The VRUs are connected to flare stack S/V 241-01, the VRU Flare, to control VOC emissions

during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes leaks from process equipment including one (1) compressor (identified as J-3E located at VRU-100), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system. The facility may also include insignificant activities listed in Section A.4 of this permit.

(2) As part of the VRU 100/200 Whiting Atmospheric Relief Project (WARP), per SPM 089-25488-00453, the pressure relief discharges that vented to the existing VRU 100/200 vent stack are being re-routed to the VRU flare.

(f) **(A)** The Vapor Recovery Unit 300 (VRU 300), identified as Unit ID 150. Light ends and naphtha are separated in the VRU using a series of distillation towers. This unit is connected to flare stack S/V 241-01, the VRU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) off-gas knock out drum (D-400) which exhausts to flare stack S/V 241-01.

(2) Leaks from process equipment, including two (2) compressors (identified as K-340 and K-351), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation system.

(B) Vapor Recovery Unit VRU 400 for the New Coker (#2 Coker), **to be installed as part of the CXHO Project.**

(o) The No.3 Ultraformer Unit (No. 3 UF), identified as Unit ID 220, commissioned in 1958. **The majority of the unit was shutdown in March 2007, including the H-1, H-2 and F-7 heaters, catalyst filled reactors and the internal scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation steps of the regeneration process. The unit consists of the C-2 Splitter Tower, the D-18 flare gas separator, D-24 knock-out drum and associated piping**. ~~used to upgrade low-octane naphtha to gasoline blending material and chemical feedstocks. The reforming section consists of a series of process furnaces and catalyst-filled reactors in which the naphtha is heated and converted from straight chain to aromatic compounds. The reactor products are separated by distillation for further processing or blending into gasoline. The No. 3 Ultraformer is connected to flare stack S/V 220-04, the UIU flare, to control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance and reactor regenerations. The No.3 Ultraformer includes the following sources of emissions and may also include insignificant activities listed in Section A.4 of this permit.~~

~~(1) Three (3) process heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:~~

~~Heater Identification~~	~~Maximum Heat Input Capacity (MMBtu/hr)~~	~~Stack Exhausted To~~	~~Emission Controls~~

~~H-1 (will be shut down as part of CXHO)~~	~~240~~	~~220-01~~	~~None~~
~~H-2 (will be shutdown as part of CXHO)~~	~~185~~	~~220-02~~	~~None~~
~~F-7 (will be shutdown as part of CXHO)~~	~~23~~	~~220-03~~	~~None~~
~~Regeneration Furnace~~	~~Not in service~~	~~Not in service~~	~~None~~

~~(2)~~**(1)** One (1) flare gas separator (D-18) with emissions vented to vessel D-24, which exhausts to flare stack S/V 220-04.

~~(3) Five (5) catalyst filled reactors, which are vented to flare stack S/V 220-04 during the initial catalyst depressuring and catalyst purging steps of the regeneration process.~~

~~(4) One (1) internal scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation steps of the regeneration process, which removes HAP emissions.~~

~~(5)~~**(2)** Leaks from process equipment, ~~including one (1) compressor (identified as K-1)~~, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

~~The No. 3 Ultraformer, consisting of emission units listed in (1) through (5) will be shut down as part of the CXHO project.~~

(p) The No.4 Ultraformer Unit (no. 4 UF), identified as Unit ID 224, built in 1972, upgrades low-octane naphtha to gasoline blending material and chemical feedstocks. **The front-end of the unit is a desulfurization section.** The reforming section consists of a series of process furnaces and catalyst-filled reactors in which the naphtha is heated and converted from straight chain to aromatic compounds. The reactor products are separated by distillation for further processing or blending into gasoline. **A new reactor will be installed as part of the CXHO project.** The No. 4 Ultraformer includes the following sources of emissions and may also include insignificant activities listed in Section A.4 of this permit:

(u) The Fluidized Catalytic Cracking Unit (FCU) 500, constructed in 1945, identified as Unit ID 230 and rated at 115,000 barrels per day. This facility converts hydrocarbons that boil above 500 ^{o}F into lower molecular weight products, which include gasoline and LPG. The cracking takes place as the gas oil and catalyst stream mix in the reactor. This process results in the catalyst being coated with coke, which is subsequently burned off in a regenerator. The FCU 500 includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) ... (4)

(5) ~~The FCU 500 WARP, permitted in 2008, to replace the existing FCU 500 blowdown stack, with the exhaust re-routed to the VRU flare.~~ **As part of the FCU 500 WARP, per SPM 089-25488-00453, the FCU 500 blowdown stack will be shutdown and the pressure relief discharges that vent to the blowdown stack will be re-routed to the VRU flare.**

(6) The FCU 500 turnaround (TAR) project, **per SPM 089-25488-00453** ~~permitted in 2008~~, for the repair or replacement of the power recovery turbine, and the air ring for the catalyst regenerator. The increases in emissions from FCU 500 TAR are already accounted for as CXHO project related emissions increases.

(v) The Fluidized Catalytic Cracking Unit (FCU) 600, constructed in 1946, identified as Unit ID 240 and rated at 80,000 barrels per day. This facility converts hydrocarbons that boil above 500 ^{o}F into lower molecular weight products, which include gasoline and LPG. The cracking takes place as the gas oil and catalyst stream mix in the reactor. This process results in the catalyst being coated with coke, which is subsequently burned off in a regenerator. The FCU 600 includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) One (1) catalyst regenerator. Flue gas from the regenerator passes through a waste heat recovery unit, which generates steam and an Electrostatic Precipitator for particulate matter control. The flue gas is then directed to a selective catalytic reduction (SCR) system, which chemically reduces nitrogen oxide emissions by reaction with injected ammonia, and is exhausted through stack S/V 240-01.

(2) Two catalyst storage bins, one each for equilibrium and fresh catalyst. (Spent catalyst is stored in Bin F-52, which is associated with FCU 500.)

(3) One (1) flare exhausting at stack ID S/V 230-02 (FCU Flare). The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including two (2) wet gas compressors (identified as J-3Dand J-3E), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system.

(5) ~~The FCU 600 WARP, permitted in 2008, to replace the existing FCU 600 blowdown stack, with the exhaust re-routed to the FCU flare.~~ **As part of the FCU 600 WARP, per SPM 089-25488-00453, to shutdown the existing FCU 600 blowdown stack and the pressure relief discharges that were vented to the blowdown stack will be re-routed to the FCU flare.**

(6) The FCU 600 turnaround (TAR) project, ~~permitted in 2008~~ **per SPM 089-25488-00453**, for the repair or replacement of the main fractionator overhead condensers, the slurry and pump around system, unit pump replacement, FCU flare tip replacement, **and additional controls to reduce plugging on the SCR.** ~~and addition of a soot blower~~. The increases in emissions from FCU 600 TAR are already accounted for as CXHO project related emissions increases.

(w) A portion of No. 1 Stanolind Power Station (SPS) constructed in 1928 and identified as Unit ID 501. The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas, are NOx budget units:

(1) The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Boiler Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
~~#3 Boiler~~	~~265~~	~~501-01~~	~~None~~
~~#4 Boiler~~	~~265~~	~~501-01~~	~~None~~
#5 Boiler	265	501-02	None
#6 Boiler	265	501-02	None
#7 Boiler	265	501-02	None

Note: The boilers in No. 1 Stanolind Power Station are scheduled to be shut down as part of the ~~CXHO project~~ **Consent Decree 2:96 CV 095 RL**.

(2) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(x) A portion of No. 3 Stanolind Power Station (SPS) constructed as listed below and identified as Unit ID 503. The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas, are NOx budget units:

(1) The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Boiler Identification	Installation Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
#1 Boiler	1948	575	503-01	(current) low-NO_x burners, an induced flue gas recirculation (IFGR) system, and an over fired air (OFA) system
#2 Boiler	1948	575	503-02	After CXHO: The low-NOx burners, IFGR and OFA will be replaced by conventional burners and a Selective Catalytic Reduction (SCR) system on Boilers # 1, 2, 3, 4, 6
#3 Boiler	1951	575	503-03	
#4 Boiler	1951	575	503-04	
#6 Boiler	1953	575	503-05	

(2) Five (5) direct-fired duct burners, **per SPM 089-25488-00453** ~~permitted in 2008~~, rated at 41 mmBTU/hr each, equipped with low NOx burners and controlled by a Selective Catalytic Reduction (SCR) system. ~~The~~

~~burners are also equipped with CO analyzers for measuring emissions of CO.~~

(3) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(y) Hazardous Waste Treatment System:

~~Dewatering and thermal desorption system for processing sludge, to be installed as part of CXHO project, including dissolved air flotation skimmimgs (DAF) and API oil/water separator sludge, equipped with a wet scrubber and carbon canister system to optimize absorption of hydrocarbons. The feed rate capacities at the dewatering system and thermal desorption systems are 90,000 and 22,500 tons per year, respectively. This facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of the permit:~~

Dewatering and thermal desorption system for processing sludge, per SPM 089-25488-00453, including dissolved air flotation skimmings (DAF) and API oil/water separator sludge, The dewatering system will be equipped with a wet scrubber and carbon canister system and the thermal desorption unit will be equipped with a vapor recovery system to optimize absorption of hydrocarbons. The feed rate capacities at the dewatering system and thermal desorption systems are 22,500 tons of feed per year and 9,000 dry tons of solids per year, respectively. This facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of the permit:

(1) Two (2) centrifuges;

(2) Two (2) sludge surge tanks;

(3) One (1) oil/water mixture surge tank;

(4) One (1) enclosed auger transfer system;

(5) One (1) vapor recovery system **on the thermal desorption unit** including: an oil condensing/scrubbing system, a water condensing/scrubbing system, and an oil water separator. Uncondensed vapors from this system are routed to the two (2) diesel fired burners for destruction of VOCs.

Insignificant Activity:

(6) Two (2) diesel fired burners rated at 4 mmBTU/hr each, for the thermal desorption system.

(aa) Oil Movements, identified as Unit 640. This facility is used to store, blend, and ship products. Gasoline blending components are custom blended into various grades of gasoline. Additive and other compounds are blended into the products to give them their unique characteristics. Furnace oil and other distillates are also blended using components from process units or storage. Crude oil and feedstocks for process units and products are also stored at this location. Product loading operations include the pipeline and railcar racks. This facility

includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:

(1) One (1) internal floating roof storage tank identified as 3730, storing ethanol, constructed in 1955, with a maximum storage capacity of 1,050,721 gallons.

(2) Ten (10) external floating roof storage tanks storing petroleum hydrocarbon with vapor pressure less than 15 psia, comprising the following tanks:

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3529	1948	858,000
3637	1956 permitted in 2008 for reconstruction **(SPM 089-25488-00453)**	6,353,000
3901	1956	1,906,000
3902	1956	1,906,000
3915	1980	6,353,460
3916	1980	13,666,998
3917	1980	25,413,839
3918	1980	13,666,998
3919	1980	13,666,998
3920	1980	13,666,998

(jj) ~~The refinery operates eleven hydrocarbon flares.~~ **The refinery operates ten eleven hydrocarbon flares. The PIB flare is operated by INEOS.** The flares are used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

The flares are identified as follows:

Flare	Stack ID.	Date of Installation	Dimensions	Process Units Normally Controlled by the Flare System *	Maximum Capacity (MMBtu/hr)	Pilot Fuel Type
4UF Flare	224-06	1972	H = 200 ft, D = 2.5 ft.	ARU, CFU, BOU, 4UF	15,000	Fuel Gas and Natural Gas
FCU flare	230-02	1945	H = 200 ft. D = 2.0 ft.	FCU 600	5620	Fuel Gas and Natural Gas
UIU Flare	220-04	1958	H = 199.5 ft. D = 2.5 ft.	ISOM, 3UF, 2TP, CRU	7550	Fuel Gas and Natural Gas
VRU Flare	241-01	Unknown	H = 200 ft. D = 2.0 ft.	VRU 100,VRU200, VRU 300, FCU 500	1596	Fuel Gas and Natural Gas
Alky Flare	140-01	1961	H = 199.5 ft D = 2.5 ft.	PCU, Alky	3920	Fuel Gas and Natural Gas
SRU Flare	162-03	1971	H = 300 ft. D = 1.5 ft.	SRU	688	Fuel Gas and Natural Gas
DDU Flare	698-02	1993	H = 200 ft. D = 1.5 ft.	DDU, HU, Coker, DHT	6000	Fuel Gas and Natural Gas
LPG Flare	604-01	1986	H = 50 ft. D = 1.2 ft.	LPG storage vessels and loading facilities	30	LPG

Flare	Stack ID.	Date of Installation	Dimensions	Process Units Normally Controlled by the Flare System *	Maximum Capacity (MMBtu/hr)	Pilot Fuel Type
PIB Flare**	2	1982	H = 250 ft. D = 3.0 ft.	RGP/PGP Loading Rack	540,000 lb/hr	Fuel Gas and Natural Gas
GOHT Flare***	802-03	Installed as Part of CXHO	H = 316 ft. D = 3.5 ft	GOHT	TBD	Fuel Gas and Natural Gas
South Flare***	800-04	Installed as Part of CXHO	H = 350 ft. D = 5 ft	New Coker (#2 Coker), 12PS, Sulfur Recovery Complex	TBD	Fuel Gas and Natural Gas

* - During emergencies or flare outages, some emission units or streams may be controlled by an alternate flare system that complies with the same applicable requirements as the flare normally used to control the emissions for those units.
** - Owned and operated by INEOS USA, LLC. (Plant I.D. 089-00076).
*** - Flares are equipped with a flare gas recovery system. Under normal operation the recovered gas streams will be sent to vapor recovery/treating area for removal of H_2S and heavy components before being utilized in the refinery fuel gas system.

(oo) Two (2) new boilers, identified as New Boiler 1 and New Boiler 2, **per SPM 089-25488-00453**, ~~permitted in 2008,~~ each rated at 580 million BTU per hour, equipped with low-NOx burners and/or Selective Catalytic Reduction (SCR) for control of NOx, using either blended natural gas and refinery gas or only refinery fuel gas. A separate TRS CEMS shall be installed to measure the sulfur content of the fuel gas or fuel gas-natural gas blend fed to New Boiler 1 and New Boiler 2.

A.4 Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)]

This stationary source also includes the following insignificant activities, as defined in 326 IAC 2-7-1(21):

(a) ... (ee)

(ff) Three (3) emergency firepump engines, identified as Firepump 1, 2 and 3, **per SPM 089-25488-00453**, ~~permitted in 2008,~~ each rated at 390 HP.

(gg) One (1) concrete crushing process, **per SPM 089-25488-00453**, ~~permitted in 2008,~~ with a maximum processing capacity of 120 tons per hour, having two (2) transfer points.

BP Comment 2:

Condition D.0.1(b)(2) has two compliance equation listed. The first equation should be deleted.

Response:

The first equation under Condition D.0.1(b) has been deleted:

(b) Emissions from Boilers and Process Heaters shall be calculated as follows:

~~(1) For new heaters to be installed as part of the CXHO project, including replacement heaters, for pollutants that do not have a CEMS, the monthly emissions shall be calculated as follows:~~

$$\cancel{Emissions\left(\frac{ton}{mo}\right) = (EF) * HI * \frac{1\,ton}{2{,}000\,lb}}$$

~~Where:~~

~~(5) HI (6) = (7) Total actual heat input into unit i, in mmBtu, for the month~~

~~(8) EF (9) = (10) Emission factor (lb/mmBTU) for heater as represented in Table D.0.1 or a more representative emission factors as verified through source testing per Condition D.0.3.~~

~~(2)~~ **(1)** Emissions increases each month from the existing modified and affected process heaters and boilers not equipped with a CEMS shall be calculated as follows based on the emission factors in Table D.0.1 or a more representative emission factors as verified through source testing per Condition D.0.3:

E = (Actual Heat Input - Baseline Heat Input) (mmBTU) x Emission Factor (lb/mmBTU)

$$Emissions\left(\frac{ton}{mo}\right) = \left((HI_A * EF_A) - (HI_B * EF_B)\right) * \frac{1\,ton}{2{,}000\,lb}$$

Where,

HI_A = Actual Heat Input (mmBtu/mo)
HI_B = Baseline heat input (mmBTU/mo)

EF_A = Actual emission factor (lb/mmBTU)
EF_B = Baseline emission factor (lb/mmBTU).

BP Comment No. 3:

Coke Pile should be corrected to Coke Handling System in D.2.11(b) in permit and Technical Support Document.

Response:

Condition D.2.11(b) has been modified as follows:

D.2.11 Fugitive Dust Control Plan [326 IAC 6.8-10]

(a) Until the shutdown of the No. 11B Coker and the associated emissions units:

Pursuant to 326 IAC 6.8-10-4 (formerly 326 IAC 6-1-11.1) the Permittee shall control fugitive particulate matter emissions from No. 11B Coker and ~~Coke Pile~~ **Coke Handling System** according to the Fugitive Dust Control Plan (FDCP), included as Appendix C. If it is determined that the control procedures specified in the FDCP do not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require that the FDCP be revised and submitted for approval.

(b) Pursuant to 326 IAC 6.8-10-4 (formerly 326 IAC 6-1-11.1), the Permittee shall control fugitive particulate matter emissions from the New Coker (#2 Coker) and ~~Coke Pile~~ **Coke Handling System** according to the updated Fugitive Dust Control Plan (FDCP) submitted on January 30, 2008, included as Appendix C. If it is determined that the control procedures specified in the FDCP do not demonstrate compliance with the fugitive emissions limitations, IDEM, OAQ may require that the FDCP be revised and submitted for approval.

BP Comment No. 4:

Conditions D.3.4 and D.3.5(a) are missing statements "until shutdown". In addition, heaters H-101A, H-101B, and H-102 need to be added to this condition since 40 CFR 60, Subpart J is applicable to these heaters.

Response:

D.3.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

(a) Pursuant to SPM 089-15202-00003, issued on April 24, 2002 and 40 CFR 60.104(a)(1), **until these heaters are shutdown**, the Permittee shall comply with the requirements specified in Section E.2 for following process heaters: H-1AS and H-1AN Preheaters, H-1B Preheater, H-2 Vacuum Heater, H-1CN Crude Preheater, H-1CS Crude Preheater, and H-1CX Crude Preheater.

(b) The Permittee shall comply with the requirements specified in Section E.2 for the following process heaters: H-101A, H-101B, and H-102.

D.3.5 Emission Offset [326 IAC 2-3], Prevention of Significant Deterioration [326 IAC 2-2] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

(a) Pursuant to CP 089-2055-00453 issued on March 12, 1992, **until heater H-1CX is shutdown,** nitrogen oxide emissions from the 12 Pipe Still H-1CX furnace shall not exceed 0.10 lb/MMBtu. Compliance with this limit renders 326 IAC 2-3 not applicable. The H-1CX furnace shall also be equipped with low NO_x burners.

BP Comment No. 5:

Conditions are not numbered sequentially in the permit.

Response:

All conditions in the permit have been renumbered sequentially.

BP Comment No. 6:

D.4 facility description box is missing the alternative operating scenario post-OCC.

Response:

The D.4 facility description box has been modified as follows:

Main Operating Scenario Pre-CXHO: Approximately 80% of tail gases from the three trains are sent to the B/S TGU, with the remainder sent to the SBS TGU. Alternate Operating Scenario #1 Pre CXHO:

One train and the B/S TGU are not operate. Tail gases from the other two trains are sent to the SBS TGU.

Alternate Operating Scenario #2 Pre CXHO:
The B/S TGU is not operated. Tail gases from the three trains are sent to the SBS TGU.

Alternate Operating Scenario #3 Pre CXHO:
The SBS TGU is not operated. Tailgases from the three trains are sent to the B/S TGU.

Main Operating Scenario Post CXHO:
The tail gases from the five trains are sent to both of the COTs.

Alternate Operating Scenario #1 Post-CXHO:

One of the COTs is not operated and the tail gases from the five trains are sent to the other COT.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

BP Comment No. 7:

The statement "following the completion of the CXHO project" needs to be changed to "after startup of New Coker (#2 Coker)" in the following Conditions: D.9.3(f), D.10.3(e), D.11.3(e), D.16.3(b), D.20.3(b).

Response:

The “completion of the CXHO project” is now defined in D.0.1 (See the Response to EPA Comment #1), therefore it is not necessary to make this change.

BP Comment No. 8:
D.15 facility description box is missing the statement “(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)”

Response:

The facility description box has been changed as follows:

SECTION D.15 FACILITY OPERATION CONDITIONS - No. 3 Ultraformer Unit

Facility Description [326 IAC 2-7-5(15)]:

(o) The No.3 Ultraformer Unit (No. 3 UF), identified as Unit ID 220, commissioned in 1958. The majority of the unit was shutdown in March 2007, including the H-1, H-2 and F-7 heaters, catalyst filled reactors and the internal scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation steps of the regeneration process. The unit consists of the C-2 Splitter Tower, the D-18 flare gas separator, D-24 knock-out drum and associated piping.

The No. 3 Ultraformer is connected to flare stack S/V 220-04, the UIU flare, to control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance and reactor regenerations. The No.3 Ultraformer includes the following sources of emissions and may include insignificant activities listed in Section A.4 of this permit.

(1) One (1) flare gas separator (D 18) with emissions vented to vessel D 24, which exhausts to flare stack S/V 220 04.

(2) Leaks from process equipment, including one (1) compressor (identified as K 1), pumps, pressure relief devices, sampling connection systems, open ended valves or lines, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

BP Comment No. 9:

Condition D.24.13(d) should be corrected to refer to "Condition" instead of "Conditions".

Response:

Condition D.24.13(d) has been modified as follows:

D.24.13(d) Pursuant to 326 IAC 3-5-7 and to document compliance with Condition~~s~~ D.24.4, the Permittee shall submit reports of excess CO emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:
(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,

BP Comment No. 10:

In the TSD, in the Table titled "Permit Level Determination - PSD or Emission Offset", the footnote "Net emissions decreases are shown within brackets ()" should be deleted. In addition, footnote 6 provides a table for the de minimis netting analysis which needs to be updated to include correct emissions numbers.

Response:

IDEM prefers that the Technical Support Document reflect the draft permit that was on public notice. Therefore, changes have not been made to the Technical Support Document. In order to maintain a record of the comments submitted by the Permittee, the following corrections are included in this addendum to the Technical Support Document:

	Potential to Emit (tons/year)[3]						
	PM	**PM10[5]**	**SO_2**	**VOC[6]**	**CO**	**NO_X**	**Pb**
Project Emissions Increase	138.9	216.7	277.7	225.6	541.8	456.7	0.041
Net Emissions Increase (NEI) with Past Contemporaneous Increases and Decreases	-17.5	60.5	(see footnote) ***	239.0	602.2	538.5	-0.02
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases related to CXHO (phased construction) [1, 4]	-204.2	-5.0	(see footnote) ***	163.9	351.6	18.7	-0.02
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases – non-CXHO (phased shutdown) [1]	-281.9	-1.6	(see footnote) ***	-6.3	-23.7	-28.9	-0.02
Total for Modification after Netting[2]	-281.9	-41.6	(see footnote) ***	-6.3	-23.7	- ~~28.9~~ **-0.6**	-0.02
Significant Level or Major Source Threshold	25	15	40	25	100	40	0.6

[1] The details of the phased construction of new emissions units, installation of control devices on existing emissions units, and scheduled shutdown of existing emissions units are included in Appendix A of this Technical Support Document. ~~Net emissions decreases are shown within brackets ().~~

[6]VOC netting analysis performed per 326 IAC 2-3 for VOC emissions evaluation based on the NSR program effective under the 8-hour ozone standard. Pursuant to South Coast Air Quality Mgmt. Dist. v. EPA, 472 F.3d 882 (D.C. Cir., December 22, 2006), the VOC de minimis threshold of 25 tons per year has been used for applicability determination of emission offset rules as follows:

VOC Project Emissions Increase (tpy)	**202.5**
~~Net Emissions Increase (NEI) with Past Contemporaneous Increases and Decreases~~ **PEI (Project Emissions Increases) Affected Units**	~~14.8~~ **23.1**
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases related to CXHO (phased construction) [1, 4]	**177.7**

Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases – non-CXHO (phased shutdown) [1]	-14.8
Total for Modification after Netting[2]	-14.8
VOC De Minimis threshold	25

BP Comment No. 11:

The draft permit has the following typographical errors:

Condition D.3.6 header and (b) - GGG should be GGGa, and E25 and E26

Condition D.2.17(d) - should reference Subpart GGGa instead of GGG

Condition D.19.13 - numbering sequence should be (d), (e), (f), (g)

Condition D.44.13 - numbering sequence should be (g), (f)

Response:

The numbering errors in Conditions D.19.13 and D.44.13 have been corrected. The following changes have been made:

D.2.17 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.2.3 and D.2.10, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the No. 11B Coker process heaters. The Permittee shall comply with this requirement until the shutdown of the No. 11B Coker and the associated emissions units.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.2.5, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.2.6(a), the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 60, Subpart GGG**a** and 40 CFR 63, Subpart CC and to document compliance with Condition D.2.6(a), the Permittee shall submit reports as specified in Sections E.1, **E.25 and E.26** ~~E.4, and E.13~~.

D.3.6 Equipment Leaks of VOC and Hazardous Air Pollutants (HAPs)[326 IAC 12] [326 IAC 8-4-8] [40 CFR 60, Subpart GGG**a**] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of

the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG**a** and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, **E.25 and E.26** ~~E.4, and E.13~~ for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

BP Comment No. 12:

Due to the scope of this project and the longer time period over which the modifications will be made, BP will need additional time to develop Preventive Maintenance Plans (PMPs) for the new and modified equipment.

Response:

Condition B.10 - Preventive Maintenance Plan has been modified as follows:

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)] [326 IAC 2-7-6(1) and (6)] [326 IAC 1-6-3]

(a) The Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) within ninety (90) days after the effective date of this permit **or prior to startup of each respective modification or new unit, whichever is later,** for the source as described in 326 IAC 1-6-3. At a minimum, the PMPs shall include:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

BP Comment No. 13:

The operating requirement under Condition D.0.2(b) should also apply for period of time when the BTU analyzers are down.

Response:

The following change has been made:

D.0.2 Operating Requirements

(a) After the installation of the continuous BTU analyzers at fuel mixing drums, in order to demonstrate compliance with emissions limitations, the continuous BTU analyzer shall be calibrated, maintained, and operated for determining compliance with the firing rate limits for heaters and boilers that are new, modified or affected units related to the CXHO project.

(b) Prior to the installation of the continuous BTU analyzers **and during periods of time when the BTU analyzers are down**, in order to demonstrate compliance with the firing rate limits on heaters and boilers involved in the CXHO project, the Permittee shall:

(1) Continuously monitor the fuel flow rates at the heaters and boilers;

(2) Conduct a monthly analysis of fuel gas samples taken once per week in order to determine monthly averaged BTU content of the fuel gas in each mixing drum; and

(3) Determine the monthly firing rates for heaters and boilers based on the fuel flow rates at each heater and boiler and the monthly averaged BTU content of the fuel gas in the mixing drums.

BP Comment No. 14:

There is a potential that Tank 8a could trigger NSPS Subpart GGGa. This cannot be determined until the engineering of this project is further along. BP suggests that the following language be added to Condition D.1.6 to address Subpart GGGa for No. 11 PS:

Prior to startup of Tank 8a, BP shall make a determination as to whether 40 CFR 60 Subpart GGGa has been triggered by the changes made as a part of the projects authorized by SSM 089-25484-00453. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

Response:

The following change has been made:

D.1.6 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] **[40 CFR 60, Subpart GGGa]**

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems located at No. 11A Pipe Still.

(c) Prior to startup of Tank 8a, BP shall make a determination as to whether 40 CFR 60, Subpart GGGa has been triggered by the changes made as a part of the projects authorized by SSM 089-25484-00453. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

BP Comment No. 15:

In Section D.3, all references to crude preheater H-1CS should be deleted as this unit is no longer in operation.

Response:

All references to H-1CS have been deleted throughout Section A.2 and Section D.3.

BP Comment No. 16:

Condition D.3.14 has duplicate requirements under (a) and (b).

Response:

Condition D.3.14(b) has been deleted as follows:

D.3.14 Continuous Emissions Monitoring

~~(a)~~ In order to demonstrate compliance with Conditions D.3.5 and D.3.12, the Total Reduced Sulfur, NOx, and CO continuous emission monitoring systems (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2, NOx, and CO emissions limits for H-101A, H-101B, and H-102 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

~~(b) In order to demonstrate compliance with Condition D.3.12, the CO continuous emission monitoring systems (CEMS) shall be calibrated, maintained, and operated for demonstrating compliance with the CO emissions limits for H-101A, H-101B, and H-102 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.~~

BP Comment No. 17:

Conditions D.4.11 and D.4.14(a) through (f) are only applicable until the referenced emissions units are shutdown.

Response:

The following changes have been made:

D.4.11 Operating Requirement

Until the SRU incinerator is shutdown:

Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitation for the SRU incinerator in Condition D.4.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

D.4.14 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Condition D.4.3, the Permittee shall maintain daily records of the following for the SRU incinerator **(until shutdown)** for each day that the unit is operated:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.4.2, the Permittee shall maintain records for the SRU **(until shutdown)** as specified in the Continuous Compliance Plan.

(c) Pursuant to 326 IAC 7-4.1-3(b)(1)(C) and to document compliance with Condition D.4.3, the Permittee shall maintain daily records of the following for the B/S TGU **(until shutdown)**:

(1) total reduced sulfur concentration,

(2) hydrogen sulfide concentration, and

(3) calculated stack gas flow rates.

(d) Pursuant to 326 IAC 7-4.1-3(b)(1)(D) and to document compliance with Condition D.4.3, the Permittee shall maintain daily records of the following for the SBS TGU **(until shutdown)**:

(1) sulfur dioxide concentration, and

(2) stack gas flow rate.

(e) To document compliance with Condition D.4.4(a), the Permittee shall keep the following records for the B/S TGU **(until shutdown)**:

(1) one-minute block averages from the TRS CEM, and

(2) average TRS emission rates, calculated as SO_2, per twelve (12) consecutive month period.

(f) To document compliance with Conditions D.4.4(b), the Permittee shall keep the following records for the SBS TGU **(until shutdown)**:

(1) one-minute block averages from the SO_2 CEM, and

(2) average SO_2 emission rate per twelve (12) consecutive month period.

BP Comment No. 18:

Condition D.4.15(h) should include CO, since the unit is equipped with a CO CEMS.

Response:

Condition D.14(h) has been modified as follows:

(h) In order to demonstrate compliance with Condition D.4.4, upon start-up of COT 1 and/or COT 2, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 **and CO** emissions at COT1 and COT2 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

BP Comment No. 19:

In Section D.4 - Facility Description, Tank TK-410 is described incorrectly as permitted in 2008. This tank was permitted in 2006 in MSM No. 089-23341-00453.

Response:

The facility description of Tank No. TK-410 has been modified as follows:

A.2. .....

(d)(17) One (1) sour water storage tank, identified as TK-410, **permitted in 2006** ~~per MSM 089-23341-00453~~, having a maximum storage capacity of 4,351,200 gallons and equipped with an external floating roof. The maximum true vapor pressure of the material stored in this tank is less than 0.5 psia.

D.4 .....

(17) One (1) sour water storage tank, identified as TK-410, permitted in ~~2008~~ **2006**, having a maximum storage capacity of 4,351.200 gallons and equipped with an external floating roof. The maximum true vapor pressure of the material stored in this tank is less than 0.5 psia.

BP Comment No. 20:

Condition D.18.5 has references to construction permits that need to be modified for clarification purposes.

Response:

Condition D.18.5 has been modified as follows for clarification purposes:

D.18.5 Emission Offset and Prevention of Significant Deterioration (PSD) [326 IAC 2-2] [326 IAC 2-3]

~~Pursuant to Permit CP 089-2055 -00003 issued on March 12, 1992, and amended on February 19, 1999, the~~ **The** Permittee shall comply with the following emission limitations and operating conditions:

(a) Prior to start-up of the new coker (#2 Coker), nitrogen Oxide (NO_x) emissions from the WB-301 and WB-302 Process Heaters shall not exceed 0.065 lb/MMBTU. This is equivalent to total NO_x emissions of 36.6 tons per year from the WB-301 and WB-302 Process Heaters.

(b) Pursuant to permit CP 089-2055-0003 **issued on March 12, 1992, and amended on February 19, 1999**, carbon Monoxide (CO) emissions from the WB-301 and WB-302 Process Heaters shall not exceed 0.04 lb/MMBTU. This is equivalent to total CO emissions of 22.5 tons per year from the WB-301 and WB-302 Process Heaters.

(c) Prior to start-up of the new coker (#2 Coker), the input of natural gas and natural gas equivalents to Process Heaters WB-301 and WB-302 shall be limited to a total of 1089.7 million cubic feet (MMcf) per twelve (12) consecutive month period, with compliance determined at the end of every month. For the purpose of determining compliance with this limit, every one (1.0) MMcf of refinery gas usage shall be considered equivalent to one (1.0) MMcf of natural gas usage.

(d) **Pursuant to permit CP 089 2055 0003 issued on March 12, 1992, and amended on February 19, 1999, all** ~~All~~ compressor seals in volatile organic compound (VOC) service shall be purged and vented to the flare header.

(e) **Pursuant to permit CP 089 2055 0003 issued on March 12, 1992, and amended on February 19, 1999, the** ~~The~~ Propane Dewaxing Unit and Asphalt Oxidizer Nos. 2 and 3 shall remain inoperative.

Compliance with these limits makes 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) and 326 IAC 2-3 (Emission Offset) not applicable.

BP Comment No. 21:

Condition D.21.4(c) incorrectly refers to ARU instead of FCU 500.

Response:

D.21.4 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Prior to start-up of the FCU 500 after the TAR project, BP shall make a determination as to whether 40 CFR 60, Subpart GGGa has been triggered by component changes made on the ~~ARU~~ **FCU 500** as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

BP Comment No. 22:

Condition D.22.4(c) incorrectly refers to ARU instead of FCU 600.

Response:

Condition D.22.4 has been modified as follows:

D.22.4 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Prior to start-up of the FCU 600 after the TAR project, BP shall make a determination as to whether 40 CFR 60, Subpart GGGa has been triggered by component changes made on the ~~ARU~~ **FCU 600** as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

BP Comment No. 23:

The references to boilers 3 and 4 should be deleted from Conditions D.23.6 and D.23.10(b), since these boilers are no longer in operation.

Response:

Conditions D.23.6 and D.23.10 are modified as follows:

D.23.6 Nitrogen Oxides Budget Trading Program [326 IAC 10-4]

Until the shutdown of boilers ~~#3, 4,~~ 5, 6, and 7:

Pursuant to 326 IAC 10-4-1(a), the Permittee shall comply with Nitrogen Oxides Budget Trading program for boilers ~~#3~~ **5** through #7 which are specified in Section E.11.

D.23.10 Record Keeping Requirements

Until the shutdown of boilers #5, 6, and 7:

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.23.3 and D.23.9, the Permittee shall maintain a daily record of the following for the No. 1SPS Boilers:

(1) operational status of each facility,

(2) fuel type,

(3) average daily sulfur content for each fuel type,

(4) average daily fuel gravity for each fuel type,

(5) total daily fuel usage for each type, and

(6) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(p) and 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.23.1(b), the Permittee shall maintain records for the Boilers ~~#3, #4,~~ #5, #6, and #7 as specified in the Continuous Compliance Plan.

BP Comment No. 24:

In Section D.24, the applicability of 40 CFR 60, Subpart J should be added for the duct burners. In addition, Condition D.24.9(b) should also reference D.24.4(c).

Response:

The following changes have been made:

D.24.5 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the No. 3SPS Boilers **and the five (5) duct burners**.

D.24.9 Operating Requirement

(a) Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003 and SPM 089-18588-00453, issued July 15, 2004, fuel oil shall not be used as fuel for the No. 3SPS Boilers.

(b) Compliance with the limits in Condition D.24.4(a), (b), **(c)** and (g) shall be demonstrated as specified in Condition D.0.3.

BP Comment No. 25:

Section D.24 does not include references to NESHAP and NSPS recordkeeping and reporting requirements as included in the other D sections.

Response:

D.24.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.24.3 and D.24.9 the Permittee shall maintain a daily record of the following for the No. 3 SPS Boilers:

(1) operational status of each facility,

(2) fuel type,

(3) average daily sulfur content for each fuel type,

(4) average daily fuel gravity for each fuel type,

(5) total daily fuel usage for each type, and

(6) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(p) and 326 IAC 6-1-10.1(n)(5)), and to document compliance with Condition D.24.1(b), the Permittee shall maintain records as specified in the Continuous Compliance Plan.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.24.6(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) In order to demonstrate compliance with Condition D.24.3, the Permittee shall maintain records of monthly firing rates and CO emissions at No. 3 Stanolind Power Station boilers 1, 2, 3, 4, 6, and the five (5) duct burners.

(e) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.24.5, the Permittee shall maintain the records specified in Section E.2.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.24.8, the Permittee shall maintain records specified in Section E.6.

D.24.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.24.3 and D.24.9, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour for the No. 3 SPS Boilers.

(b) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.24.6(a) the Permittee shall submit reports as specified in the LDAR plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.24.5, the Permittee shall submit reports as specified in Section E.2.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.24.8, the Permittee shall submit reports as specified in Section E.6.

~~(c)~~ **(e)** In order to demonstrate compliance with Condition D.24.4, the Permittee shall submit a quarterly summary of the monthly firing rates and CO emissions the boilers 1, 2, 3, 4, 6 and five (5) duct burners to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

~~(d)~~ **(f)** Pursuant to 326 IAC 3-5-7 and to document compliance with Condition ~~D.24.4~~ **D.24.3**, the Permittee shall submit reports of excess CO emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
    (A) Date of downtime.
    (B) Time of commencement.
    (C) Duration of each downtime.
    (D) Reasons for each downtime.
    (E) Nature of system repairs and adjustments

BP Comment No. 26:

Condition D.32.5 - requirement under 40 CFR 63, Subpart DDDDD, should be deleted.

Response:

Condition D.32.5 has been deleted, and the remaining conditions renumbered. References to the renumbered conditions have been corrected accordingly.

~~D.32.5 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements specified in Section E.20 for the process heaters F-1 and F-2, which comprise the affected source for the large gaseous fuel subcategory.~~

BP Comment No. 27:

Condition D.43.3(b) references GOHT and incorrect ID no., which should be corrected to Unit ID 801.

Response:

D.43.3 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

~~(b)~~ Pursuant to 40 CFR 63, Subpart CC and 40 CFR 60, Subpart VV, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of VOCs and HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems located at GOHT unit, **located at HU unit, identified as Unit ID 801.** ~~identified as Unit ID 802.~~

BP Comment No. 28:

Conditions D.44.4 and D.44.6 are duplicative. In addition, Condition D.44.8 does not include a compliance method for emission limits that do not have averaging periods specified in Condition D.44.3. The following statement should be added:

Compliance with the limits in Condition D.44.3(e) and (f) shall be demonstrated as specified in Condition D.0.3.

Response:

Condition D.44.6 has been deleted and the remaining conditions renumbered and Condition D.44.8 (renumbered as D.44.7) has been modified. The Table of Contents has been modified accordingly.

~~D.44.6 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]~~

~~Pursuant to 40 CFR 60, Subpart J, the Permittee shall comply with the requirements specified in Section E.2 for New Boiler 1 and New Boiler 2.~~

D.44.~~7~~ **8** Operating Requirement

(1) In order to demonstrate compliance with D.44.3, fuel oil shall not be used as fuel for New Boiler 1 and New Boiler 2.

(2) Compliance with the limits in Condition D.44.3(e) and (f) shall be demonstrated as specified in Condition D.0.3.

BP Comment No. 29:

Condition D.45.2(a) should be clarified as follows: "The total hours of operation for **each of** the three firepump engines shall not exceed 500 hours per year."

Response:

Upon further review, IDEM has determined that the emissions calculations are based on 500 hours of operation for each firepump engine. Therefore, Condition D.45.2(a) has been modified as follows:

D.45.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) The ~~total~~ hours of operation for **each of** the three firepump engines shall not exceed 500 hours per year.

BP Comment No. 30:

In Condition D.35.4, GOHT and South flares should be subject to 40 CFR 60, Subpart GGGa instead of 40 CFR 60, Subpart GGG.

Response:

The following changes have been made:

D.35.4 Equipment Leaks of VOC [326 IAC 12] [40 CFR 60, Subpart GGG] **[40 CFR 60, Subpart GGGa]**

(a) Pursuant to 40 CFR 60, Subpart GGG, the Permittee shall comply with the control device standards specified in Section E.13 for the 4UF, UIU, Alky, ~~GOHT, South~~ and DDU flares.

(b) Pursuant to 40 CFR 60, Subpart GGGa, the Permittee shall comply with the control device standards specified in Section E.25 for GOHT and South flares.

D.35.9 Record Keeping Requirements

(a) To document compliance with Condition D.35.2, pursuant to 40 CFR 63, Subpart CC, the Permittee shall maintain the records as specified in Section E.1.

(b) Pursuant to 40 CFR 61, Subpart J and to document compliance with Condition D.35.3, the Permittee shall keep records as specified in Section E.5.

(c) Pursuant to 40 CFR 60, Subpart**s** GGG **and GGGa** and to document compliance with Condition D.35.4, the Permittee shall maintain the records as specified in Section E.13 **and E.25**.

(d) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.35.5, the Permittee shall keep records as specified in Section E.2.

(e) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition D.35.8, the Permittee shall keep records as specified in Section E.10.

(f) In order to demonstrate compliance with Condition D.35.1(e), the Permittee shall maintain records of fuel usages at the GOHT and South flares.

D.35.10 Reporting Requirements

(a) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.35.2, the Permittee shall submit reports as specified in Section E.1.

(b) Pursuant to 40 CFR 61, Subpart J and to document compliance with Condition D.35.3, the Permittee shall submit reports as specified in Section E.5.

(c) Pursuant to 40 CFR 60, Subpart**s** GGG **and GGGa** and to document compliance with Condition D.35.4, the Permittee shall submit reports as specified in Section E.13 **and E.25**.

(d) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.35.5, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(e) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition D.35.8, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.10.

(f) In order to demonstrate compliance with Condition D.35.1, the Permittee shall submit quarterly reports for pilot gas and purge gas usages at the GOHT and South flares. The report submitted by the Permittee does require the certification by the "Responsible Official" as defined by 326 IAC 2-7-1(34).

BP Comment No. 31:

The GOHT is subject to 40 CFR 60, Subpart GGGa. The reference in Condition D.42.3 should be corrected accordingly.

Response:

The following change has been made:

D.42.3 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [40 CFR 60, Subpart VVa][40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 60, Subpart ~~VV~~ **GGGa**, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of VOCs and HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems located at GOHT unit, identified as Unit ID 802.

(c) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

BP Comment No. 32:

The GOHT is subject to 40 CFR 63 Subpart CC, 40 CFR 61, Subpart FF, and 40 CFR 60, Subpart QQQ for wastewater streams.

Response:

Condition D.42.4 has been added as follows, and the remaining conditions have been renumbered.

D.42.4 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14][40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ] [326 IAC 12]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

BP Comment No. 33:

Condition D.43.3(b) should reference 40 CFR 63, Subpart GGGa.

Response:

40 CFR 63, Subpart GGGa is already referenced in Condition D.43.3(c), therefore, the following change has been made:

D.43.3 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [40 CFR 60, Subpart GGGa] [40 CFR 60, Subpart VVa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(c) Pursuant to 40 CFR 63, Subpart CC ~~and 40 CFR 60, Subpart VV~~ , the Permittee shall comply with the requirements specified in Section~~s~~ E.1 ~~and E.4~~ **E.25** for equipment leaks of VOCs and HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems located at GOHT unit, located at HU unit, identified as Unit ID 801.

(c) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

BP Comment No. 34:

Section D.44 (new boilers) has recordkeeping and reporting requirements under 40 CFR 60, Subpart QQQ, but does not include a condition for the applicability of this NSPS.

Response:

Condition D.44.6 has been added as follows. The remaining conditions in section D.44 have been renumbered as well.

D.44.6 Wastewater / Waste Streams [40 CFR 60, Subpart QQQ][326 IAC 12]

Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

BP Comment No. 35:

In addition, there are a couple of additional corrections to the existing forms that we had not submitted earlier:
1. In the form on page 13 of 37 - heater F-101A should be F-101.
2. In the form on page 15 of 37 - heater B-601a should be B-601A.

Response:

The heater IDs have been corrected as requested.

BP Comment No. 36:

Conditions D.43.4 and D.43.7 are duplicative requirements.

Response:

Condition D.43.4 has been modified as follows to delete duplicative requirements for the HU flare:

D.43.4 Fuel Gas Hydrogen Sulfide (H2S) [326 IAC 12][40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for process heaters HU-1 and HU-2 ~~and the HU flare~~.

BP Comment No. 37:

BP requests that IDEM add report forms for the following limits:

1. New Coker heaters H-201, 202, and 203 - Emissions of CO and NOx are limited to 17.3 tons per consecutive 12-months and 18.2 tons per consecutive 12-months, respectively for each heater.

2. 12 PS heaters H-101A and 101B - Emissions of CO and NOx are limited to 29.5 tons per consecutive 12-months and 77.7 tons per consecutive 12-months, respectively for each heater.

3. 12 PS heater H-102 - Emissions of CO and NOx are limited to 27.5 tons per consecutive 12-months and 72.5 tons per consecutive 12-months, respectively.

4. COT1 and 2 - Total SO2 and CO emissions are limited to 194.8 tons per consecutive 12-months and 55.0 tons per consecutive 12-months, respectively.

5. 3 SPS and duct burners - After the installation of the duct burners and the SCRs, the firing rate (total) is limited to 24,303,535 MMBtu per consecutive 12-months.

6. 3 SPS and duct burners - Total CO emissions are limited to 260.3 tons per consecutive 12-months. This is required per Permit Condition 24.17(d)

7. DHT heater B-601A - Emissions of NOx and CO are limited to 7.3 tons per consecutive 12-months and 7.3 tons per consecutive 12-months, respectively. A reporting condition is not currently listed in section D.37 for this heater.

8. The GOHT F-901A and F-901B - Emissions of SO2 are limited to 2.3 tons per consecutive 12-months, for each heater. This is required per Permit Condition 42.9(b)

9. New HU heaters HU-1 and HU-2 - Emissions of NOx and CO are limited to 52.4 tons per consecutive 12-months and 60.4 tons per consecutive 12-months, respectively, for each heater. This is required per Permit Condition 43.13(b)

Response:

The following report forms have been added for the convenience of the Permittee:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION
Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: CO and NOx emissions after startup of New Coker (#2 Coker), tons per 12 consecutive month period

Facility	CO	NOx
H-201	17.3	18.2
H-202	17.3	18.2
H-203	17.3	18.2

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on:_____

Submitted by: _____

Title / Position:_____

Signature:_____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: CO and NOx emissions after startup of New Coker (#2 Coker), tons per 12 consecutive month period

Facility	CO	NOx
H-101A	29.5	77.7
H-101B	29.5	77.7

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on:_____

Submitted by: _____

Title / Position:_____

Signature:_____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

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Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: CO and NOx emissions after startup of New Coker (#2 Coker), tons per 12 consecutive month period

Facility	CO	NOx
H-102	27.5	72.5

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on:_____

Submitted by: _____

Title / Position:_____

Signature:_____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 and CO emissions after startup of New Coker (#2 Coker), tons per 12 consecutive month period

Facility	SO2	CO
COT1 and COT2(total)	194.8	55.0

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on:_____

Submitted by: _____

Title / Position:_____

Signature:_____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: Firing rate after installation of duct burners on 3 SPS, mmBTU per 12 consecutive month period

Facility	Firing Rate
3SPS and duct burners	24,303,535

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on:_____

Submitted by: _____

Title / Position:_____

Signature:_____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: CO emissions, tons per 12 consecutive month period

Facility	CO Emissions
3SPS and duct burners	260.3

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on:_____

Submitted by: _____

Title / Position:_____

Signature:_____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
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Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: NOx and CO emissions, tons per 12 consecutive month period

Facility	CO Emissions	NOx Emissions
DHT Heater B-601A	7.3	7.3

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on:_____

Submitted by: _____

Title / Position:_____

Signature:_____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions, tons per 12 consecutive month period

Facility	SO2 Emissions
GOHT heater F-901A	2.3
GOHT heater F-901B	2.3

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on:_____

Submitted by: _____

Title / Position:_____

Signature:_____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: NOx and CO emissions, tons per 12 consecutive month period

Facility	NOx Emissions	CO Emissions
New HU heater HU-1	52.4	60.4
New HU heater HU-2	52.4	60.4

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on:_____

Submitted by: _____

Title / Position:_____

Signature:_____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

BP Comment No. 38:

Based on the issuance date of the permit for the Asphalt Plant (2/20/07) and the proposed date of the NSPS, 40 CFR 60, Subpart GGGa, the asphalt plant should be subject to Subpart GGGa instead of Subpart GGG.

Response:

The following changes have been made:

D.32.7 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [40 CFR 60, Subpart GGG**a**]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG**a**, the Permittee shall comply with the requirements specified in Sections ~~E.4 and E.13~~ **E.25 and E.26** for valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, flanges and/or other connectors in VOC service.

D.32.15 Record Keeping Requirements

(f) Pursuant to 40 CFR 60, Subpart GGGa and to document compliance with Condition D.32.7(b), the Permittee shall keep records as specified in Sections ~~E.4 and E.13~~ **E.25 and E.26**.

D.32.16 Reporting Requirements

(e) Pursuant to 40 CFR 60, Subpart GGGa and to document compliance with Condition D.32.7(b), the Permittee shall submit to IDEM, OAQ the reports specified in Sections ~~E.4 and E.13~~ **E.25 and E.26**.

BP Comment No. 39:

The refinery uses the facility-wide exemption under 40 CFR 63, Subpart DD - National Emission Standards for Hazardous Air Pollutants from Off site Waste and Recovery Operations, where off-site waste water is tracked for HAPs (benzene) to ensure that the total annual quantity of HAPs that is contained in the off-site material received at the plant is less than 1 megagram per year. Therefore, 40 CFR 63, Subpart DD should be referenced in Section D.36 of the permit.

Response:

Condition D.36.2 has been modified as follows:

D.36.2 Wastewater / Waste Streams [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ] [40 CFR 63, Subpart DD]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and

control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, subpart CC specified in Section E.1.

(d) Pursuant to 40 CFR 63, Subpart DD, the Permittee shall comply with the requirements under 40 CFR 63.680(d) specified in Section E.14 of the permit for off-site wastewater received at the refinery.

Public Comments - Technical

Technical Comment No. 1:

The following Commenters expressed concerns related to flaring events at BP Whiting refinery, and the environmental impact of the three new flares planned as part of the CXHO project: Chicago and Illinois Attorney General, Legal Environmental Aid Foundation, NRDC Group, Save the Dunes Council, RHAMC, Daniel Grelck (Lowell, IN). The comments are summarized below:

The analysis concluding that the project will result in no net emissions increases, such that NSR is not triggered, is deeply flawed, since the netting analysis failed to account for use of flares.

a. Emissions associated with the normal operation of the flares have not been accounted for. At least one flare is accounted for as an insignificant activity, with all other emissions unaccounted for. The permit states the flare have insignificant emissions, however, no operational limits have been placed on the use of the flares.

b. The new flares are a concern since they are not included in the potential emissions. On page 8 of the Technical Support Document under Section (o), two new flares list the maximum capacity as "TBD - To be Determined". How can the total emissions be considered when these sources have not been included in the emission inventory? The Commenter urges IDEM to include these emissions.

c. The only flare emissions that were factored into the netting calculation were the miniscule amounts attributable to pilot gas and purge gas - which are the emissions when the flare is off. The netting analysis fails to account for the increased use of existing flares that will result from the project, which is expressly designed to make use of them in specified circumstances.

d. The assumption that no emissions can be expected to occur from use of the refinery flare is particularly incredible given BP Whiting's numerous past flare-related violations in connection with the existing flares. Deviation reports show that BP repeatedly exceeded the H2S 3-hr limit of 159 ppm, meaning that too much H2S was burned at the flare. The facility's eight existing flares are not only very much in use at present, but in violation of applicable CAA requirements. H2S emissions during flaring events would increase relative to baseline flaring as the refinery will be processing higher sulfur canadian tar

sand crude oils. Even if it is true that overall reliability will improve, the change in crude slate would still increase emissions of at least SO2, PM10, PM2.5 and perhaps other pollutants.

e. BP must quantify flaring emissions - including those from startup, shutdown and malfunction events, in the flares' potential to emit and clearly commit to creditable decreases in flaring emissions. The creditable decreases must be enforceable as a practical matter and have approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

f. The project will exceed significance levels for all regulated NSR pollutants once flaring emissions are properly added. The projects new high sulfur crude inputs will cause more flaring. Although the permit contain a number of provisions that concern flaring, it contains no actual limits of any kind on the frequency with which flares may be used, or on flaring emissions. The permit also fails to limit the potential to emit to the assumed zero emissions in the netting analysis.

g. The permits do not include proper BACT/LAER limits for flares and other sources. The specific measures that BP and IDEM have failed to implement concerning flare minimization performance are available for other refineries that have actually implemented the type of stringent measures required as BACT and LAER. IDEM must either establish numeric BACT or LAER limits for flares, or must present a numeric evaluation of emissions reductions expected to be achieved through work practices. Rigorous monitoring necessary for evaluating flare emissions, preventing flaring events, and ensuring enforceability is required by the CAA but missing from the draft permits. A key method of preventing unnecessary flaring is to require rigorous flare monitoring, root cause analysis of flaring, and a flare minimization plan. Current draft conditions in the permit allow unlimited flaring. Although the PSD and NA NSR netting analysis assumes that emissions associated with flare use will be zero, nothing in the draft permit actually prohibits their use, or the consequent emissions. H2S limits for flares are not a replacement for BACT/LAER for all pollutants.

h. EPA has recently issued a Notice of Violation to BP which found repeated flaring violations, demonstrating that BP is not even meeting basic flaring requirements, let alone meeting BACT/LAER requirements for the new project. According to a very recent (November 2007) Notice of Violation letter from the U.S. EPA, BP has been found to have repeatedly violated flaring and other Clean air Act requirements starting in 1986, and has continued to do so. These violations of flare monitoring requirements compound BP's failure to implement BACT and LAER controls on its flaring emissions. The violations listed in the NOV make it clear that the existing flares at the refinery - including the UIU, Alkyl, DDU and LPG flares, have already, prior to the project, undergone modifications that should have required these flares to be subject to New Source Review, and consequently BACT/LAER requirements. BP's Title V Compliance reports to IDEM also show flaring deviations.

i. Extensive data show that flaring represents an enormous source of oil refinery emissions. BP's assumption that flares will never be used for the project flies in the face of large volumes of data on flaring at other oil refineries.

j. Rigorous flare monitoring is necessary for evaluating emissions and preventing flaring, as required by the CAA but missing from the draft permit.

k. Draft permit conditions for the project allow unlimited flaring, because nothing in the permit conditions prevents individual flaring events and the associated emissions.

l. At refineries in the Bay Area sulfur dioxide emissions at refineries studied frequently exceeded 10,000 pounds, and were as high as 70,000 pounds, in a single day, while emissions of VOCs frequently exceeded thousands of pounds per day, and were recorded as high as 22,000 pounds per day. Annually, flaring events meant SOx emissions as high as 3,000 tons and VOC emissions over 1,800 tons.

m. Commenter has studied startup, shutdown, and malfunction (SSM) emissions (that is, flaring), issuing a report in 2004 documenting releases from large petrochemical plants in some states. The review of industry-filed reports showed that sometimes releases from SSM events were actually higher than total annual routine emissions reported to EPA's Toxics Release Inventory (TRI). SSM emissions of CO from Exxon Mobil's Baton Rouge facility were almost three times its reported annual CO emissions.

n. The new flares are a concern since they are not included in the potential emissions. The maximum capacity of two new flares are listed as "To be Determined" in the Technical Support Document. The maximum capacity, in millions of BTUs burned per hour is "To Be Determined" or "To be Designed".

o. The Clean Air act requires that all of the Whiting Refinery's emissions be included in the netting analysis, including emissions from the three new flares that will be built as part of the refinery's expansion projects.

p. The three burn stacks are not included in any part of the permit. Why does IDEM not require BP to install monitors on the stacks? This would allow IDEM to monitor when and how often the stacks are used.

q. Studies have shown that wind and other factors can reduce flare combustion efficiencies, which means that, although refineries typically estimate flare efficiency at 98 - 99%, more pollution is actually being released to the environment instead of being destroyed during combustion.

r. EIP (Environmental Integrity Project) found that more than half of the 37 facilities studied had SSM emissions of at least one pollutant that were 25% or more of their total reported annual emissions of that pollutant. More recent examples of SSM emissions include releases of hazardous air pollutants (HAPs) that are several tons of HAPs during one single "air emissions event".

Response:

Overall, this project is a modernization of the refinery and will result in the installation of several new units designed to operate more efficiently and with fewer malfunctions or maintenance problems. As a result, it is expected that even with the increased capacity of some of the modified units and the addition of newer, larger units, the number of flaring events will decrease. As part of the design of the new units, and the modifications to existing equipment, BP included several safety features that eliminate the need to flare during some start-up or shut-down procedures and adds redundancy to existing processes that will eliminate the need for frequent or excessive flaring. However, while we expect flaring to decrease, and as a result emissions from flaring to decrease, BP did not rely on these anticipated reductions as creditable decreases in the netting analysis. Flaring emissions that occurred during the baseline period were not counted in the baseline actual emissions. The inclusion of these emissions would have increased the baseline emissions, and given that there is an anticipated reduction in flaring emissions after the completion of the project, the overall net emission decrease from the project would be even greater. Furthermore, the project netting shows a decrease in emissions for all criteria pollutants, resulting in the project being permitted as a minor source modification. While there is expected to be a reduction in malfunctions after the modernization project, should there be unexpected

maintenance activities resulting in emissions that should be applied towards the project netting, there is sufficient room under the major modification permit threshold to account for these unexpected increases in emissions while maintaining the existing source modification permit level.

As noted by the commenters, BP will install three new flares as part of the CXHO project. These flares, which are designated as GOHT flare, South Flare, and HU flare, are included in Section A, Section D.35, Section D.43, and the TSD. The GOHT and South Flare are designed with a flare gas recirculation system that collects refinery gas from the associated emission units and recycles it back into the refinery fuel gas system. The HU flare, which is associated with the new Hydrogen Unit, will not be equipped with the flare gas recirculation system. This recirculation system is designed with sufficient capacity to collect all emissions associated with routine or normal flaring events, including routine maintenance and repair periods. In addition, the flare gas recovery system is equipped with a back-up compressor of the same capacity as the primary compressor. Operating these flares with this recirculation system is considered normal operation and the emission calculations, which include purge gas and pilot gas emissions only, is reflective of operating these units as they were intended to be operated and as they would normally be operated. The HU flare, while not equipped with the recirculation system, is designed to accommodate any flaring events resulting from malfunctions or emergencies, but will have no routine flaring that would be considered normal operation. A source's potential emissions are based on the source's normal operations under its physical and operational design. Operations during periods of startup, shutdown, or malfunction are not considered "normal operation." As a consequence, emissions during such periods have not historically been required to be included in netting calculations. This approach was articulated by the U.S. Court of Appeals and followed by the United States District Court in Alabama Power and Louisiana-Pacific, respectively. The Court in Louisiana-Pacific explained:

> The broad holding of Alabama Power is that potential to emit does not refer to the maximum emissions that can be generated by a source hypothesizing the worst conceivable operation. Rather, the concept contemplates the maximum emissions that can be generated while operating the source as it is intended to be operated and as it is normally operated. (United States v. Louisiana Pacific Corporation, 682 F. Supp. 1141, (D. Col. March 22, 1988), citing Alabama Power v. Costle, 636 F.2d 323 (D.C. Cir. 1979)).

With regard to flaring events that are the result of unplanned, non-routine emissions (malfunctions or emergencies), these emissions were not accounted for in the calculations under the "potential to emit" test that is being used for these new emission units. However, BP has included, as part of this project, all foreseeable projects where there will be planned shutdowns resulting in flaring. The emission calculations for these projects are included in Appendix E of the TSD and the ATSD. These calculations include the emissions resulting from flaring, which includes start-up and shutdown of the associated units. This approach is consistent with Federal and State regulations which govern air permitting and the "potential to emit" test (326 IAC 2-2-1(rr)). Given that the flares are new emission units, and they were evaluated using the traditional "potential to emit" test.

For the new flares, emission limits and monitoring requirements are included in D.35 and D.43 to make the future allowable part of the netting calculations practically enforcement and ensure compliance with 326 IAC 2-2 and 326 IAC 2-1.15. In addition to these conditions, IDEM is making the following revisions to the permit to clarify the Permittee's obligations with regard to flaring emissions from normal operations:

D.0.1 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

(a) Following the issuance of SPM 089-25488-00453 ~~and until the startup of New Coker (#2 Coker) and associated coke handling facilities,~~ the Permittee shall determine, on a monthly basis, the increase in emissions of SO2, NOx, PM, PM 10, CO, **Pb, Be, Hg, H2SO4,** and VOC from all new, modified and existing affected emission units at this source, and shall demonstrate, that the net emissions increases from this source remain below significant levels per twelve (12) consecutive month period beginning with issuance of SPM 089-25488-00453, in accordance with the following:

…

(g) Emissions from the GOHT, South, and HU flares shall be calculated as follows:

Emissions (ton/month) = EF_p x HI_i x 1 ton/2000 lbs

Where:

HI = Total actual heat input for the month, in mmBtu, of all gases burned in Flare i as a result of routine, or planned non-routine activities (e.g. planned startups and shutdowns of upstream units).

EF_p = The pollutants-specific emission factor (lb/mmBTU) set out below:

For SO2:

$$EF_p = \frac{C \times MW \times P \times (1/HHV_A)}{R \times T}$$

Where,

C = Flared gas total sulfur concentration (ppm)
MW = Molecular Weight (lb/lbmol)
P = Pressure (psia)
R = Ideal Gas Constant (psia*ft3/(lbmol*R))
T = Temperature (R)

HHV_A = Actual flare gas higher heating value (mmBtu/mmscf)

For NOx:

EF_p = 0.068 lb/mmBtu (+ fuel nitrogen component)

For VOC:

EF_p = 0.14 lb/mmBtu

For CO:

EF_p = 0.37 lb/mmBtu

For PM10/2.5:

EF_p = 0.0075 lb/mmBtu

For Pb:

EF_p = 4.9E-7 lb/mmBtu

For Hg:

EF_p = 1.8E-7 lb/mmBtu

For Be:

EF_p = 1.18E-8 lb/mmBtu

For H2SO4:

EF_p = 3% x (SO2 EF_p) x 98/64.06

D.0.4 Recordkeeping Requirements

In order to demonstrate compliance with Condition D.0.1, the Permittee shall maintain the following records each month, upon issuance of the SPM 089-25488-00453 ~~and until the startup of the New Coker (#2 Coker) and associated coke handling facilities~~:

(a) The emissions in tons, **calculated in accordance with D.0.1,** including fugitive emissions, of PM, PM-10, VOC, NOx, **CO, Pb, Be, Hg, H2SO4,** and SO2, from new emission units installed as part of the CXHO project during that month.

D.0.5 Reporting Requirements

…

~~(b) The reporting requirements in Condition D.0.5(a) shall no longer be applicable following the startup of the New Coker (#2 Coker). Start-up is defined as when the unit becomes operational only after a reasonable shakedown period, not to exceed 180 days, pursuant to 326 IAC 2-2-1 (jj)(7).~~

D.35.9 Continuous Monitoring – GOHT and South Flare [326 IAC 2-2]

The Total Reduced Sulfur continuous emission monitoring systems (CEMS) for the GOHT and South Flares shall be calibrated, maintained, and operated in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. For purposes of demonstrating compliance with Condition D.0.1, the SO2 emissions from the GOHT and South Flares shall be calculated as provided in Paragraph (g) of Condition D.0.1 based on the conversion of one mole of sulfur in the gas to one mole of SO2.

D.35.~~9~~**10** Record Keeping Requirements

…

D.35.~~10~~**11** Reporting Requirements

…

D.43.12 Continuous Monitoring – HU Flare [326 IAC 2-2]

The Total Reduced Sulfur continuous emission monitoring systems (CEMS) for the HU Flare shall be calibrated, maintained, and operated in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. For purposes of demonstrating compliance with Condition D.0.1, the SO2 emissions from the HU Flare shall be calculated as provided in Paragraph (g) of

Condition D.0.1. based on the conversion of one mole of sulfur in the gas to one mole of S.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.43.12~~3~~ Record Keeping Requirements

…

D.43.13~~4~~ Reporting Requirements

…

The aforementioned revisions make clear that the Permittee is required to include, in the D.0 calculations, all emissions from the new flares that result from routine operations or from planned non-routine activities such as startups and planned (non-emergency) shutdowns. However, the language would not require BP to include emissions from emergencies, malfunctions and other unplanned events, over which it has no control, which are not required to be included in netting calculations. It will be incumbent on BP to maintain the system adequately to minimize un-planned flaring events, limiting these primarily to occurrences that can be construed as "beyond their control". This will ensure that these emissions are accounted for in the netting calculations and ensure that when these emissions are compared to the increases and decreases included in the netting analysis the project remains minor under PSD, EO, and Nonattainment NSR.

Technical Comment No. 2:

(NRDC Group) The analysis concluding that the project will result in no net emissions increases, such that NSR is not triggered, is deeply flawed, due to the following:

A. The netting analysis failed to account for other emissions sources, including venting of pressure relief devices, uncontrolled loading of petroleum products onto marine vessels, residual emissions from vessel depressurization, increased coking, wastewater ponds and their systems, coke drum depressurization, coke drum VOC and PM10 from decoking, and fugitive emissions of reduced sulfur compounds. The application also did not include reduced sulfur including H2S emissions from leaks from fugitive sources. The depressurization, cooling, and decoking operations emit H2S and other reduced sulfur compounds.

1. Coke drum depressurization emissions were omitted. The South Coast Air Quality management District (SCAQMD) has measured depressurization emissions from all refineries within its jurisdiction and is proposing to initiate rulemaking to control these emissions. These emissions are viewed as considerable. The test report from Chevron's El Segundo Refinery shows 13.75 lb of total PM and 11.16 lb of VOCs per depressurization event. BP Whiting's application indicates that the project would increase coke production from 1,638 tons per day to 6,000 tons per day. Assuming 1000 tons per drum, the project would increase the number of depressurization event by over four per day. Thus, depressurization venting alone would increase total PM emissions by at least 10 tons per year and VOC emissions by 8 tons per year. Actual emissions are likely to be much higher.

2. Coke drum VOC and PM10 decoking emissions were omitted from the netting analysis. According to the depressurization report, after the blow down period, the top drum head remains open for cooling, and then the coke is cut. The emissions occurring during these events are similar to that during the blowdown event. PM10 and VOC emissions from further cooling and decoking could be roughly comparable to those from depressurization, and after corrections, could double or more the depressurization emissions.

3. Fugitive sulfur emissions were omitted - H2S and reduced sulfur compounds, including H2S, are PSD pollutants. Fugitive sources, such as leaks from valves, flanges, pumps, compressors and tanks are typically major sources of reduced sulfur compounds including H2S at refineries. The project will increase the emissions of these compounds due to the processing of Canadian tar sands. Reduced sulfur compounds including H2S will be emitted from fugitive components in the new units. Coke drum vapors are about 5% H2S by weight. The depressurization, cooling, and decoking events will emit H2S and other reduced sulfur compounds from all fugitive components of the Coker, including valves, connectors, and pumps. The application did not disclose that the coke drums will emit H2S.

B. The netting analysis inappropriately used AP-42 emission factors to calculate baseline emissions. Baseline actual emissions must be based on actual testing data from the unit or a similar unit. Actual emissions must be based on measurement or other concrete, source-specific evidence, and not on industry wide average emission factors. BP should recalculate its emissions using actual data from the facility.

C. The dozens of projects that were used to offset the CXHO project are too numerous and too complex for the public to analyze in the short time period allotted, and cannot be analyzed with the information provided without doing lengthy and time consuming public information requests.

Response:

A. IDEM received an application from BP Products North America, Inc. - Whiting Business Unit, which included a detailed netting analysis for the OCC project. The application, certified by the Responsible Official at BP products North America, Inc. - Whiting Business Unit, was for a project that is minor under the PSD (Prevention of Significant Deterioration), EO (Emission Offset), and NA NSR (Nonattainment NSR) rules under 326 IAC 2-2, 326 IAC 2-3, and 326 IAC 2-1.1-5, respectively. In this application, and as detailed in the calculations included as part of this permit, all new, modified, and affected emission units from which there will be an increase in emissions associated with the OCC project have been accounted for and included in the netting analysis. This includes the new wastewater tank, the new brine treatment system, and fugitive emissions from the new wastewater components (e.g. sewers, manholes, drains, etc.). This refinery does not have wastewater ponds.

In Section D.0 of the permit, the following requirement is included in order to make the netting analysis enforceable and to ensure that the OCC project is minor under PSD, EO and NA NSR:

Following the issuance of SPM No. 089-25488-00453 the Permittee shall determine, on a monthly basis, the increase in emissions of SO2, NOx, PM, PM 10, CO, Pb, Be, Hg, H2SO4 and VOC from all new, modified and existing affected emission units at this source, and shall demonstrate, that the net emissions increases from this project are below significant levels per twelve (12) consecutive month period beginning with issuance of SPM No. 089-25488-00453, in accordance with the following:

Following the issuance of SPM No. 089-25488-00453, the net emissions increases or decreases from the CXHO project, including fugitive emissions, shall be determined each month as follows:

Etotal = Emissions increases from new, modified, and affected emissions units during the past 12 month period
+ emissions increases from non-CXHO related projects during the past 12 month period
- creditable emissions decreases from CXHO related changes and creditable emissions decreases from non-CXHO related projects during the past 12 month period
+ emissions from creditable past contemporaneous increases
– emissions from creditable past contemporaneous decreases.

The emission calculations include all increases and decreases from the affected, modified, and new emission units, including fugitive emissions. This includes fugitive VOC emissions associated with leaks from valves, flanges, pumps, compressors, and tanks. It is not expected that there will be an increase in total reduced sulfur or H2S from fugitive sources, as with VOC. The additional reductions in sulfur through the modifications to the SRU complex (see Response to Technical Comment #8) will result in reductions in fugitive TRS and H2S emissions.

With regard to the vessel depressurization at the New Coker, these emissions will be routed to the flare gas recovery system, where they are captured and recycled in the refinery fuel gas system. In addition, emissions from loading of petroleum products onto marine vessels will decrease due to the installation of a vapor control system at the marine dock. The operation of this vapor control system is required by this permit making these decreases enforceable.

B. IDEM has determined that the use of AP-42 emission factors is appropriate for baseline emissions calculations, in situations where site-specific emission factors are not available. U.S. EPA allows the use of AP-42 emission factors as one of the calculation methods for the determination of baseline emissions.

C. IDEM agrees that several projects were used to offset emissions increases from the OCC project. However, IDEM contends that the details of the emissions decreases, the effective dates of these decreases, and details of past and scheduled future shutdowns are extensively documented in Appendix C to this Addendum to the Technical Support Document. These detailed analyses were also included in Appendix C of the Technical Support Document of the draft permit. Please refer to "Response to General Comment No. 1" for IDEM's response with regards to the time allotted for the public review process for this permit.

Technical Comment No. 3:

a. (RHAMC) The application of air emission standards in the permits relies heavily on the use of credits for past and future emission reductions. Federal law requires that all emission reductions for which BP takes credit be above and beyond those otherwise required by law. Are any of the reductions for which credits are claimed otherwise required by: a. administrative or judicial enforcement order; b. consent decree (other than Consent Decree #96 CV 095RL dated1/18/2001, as described in the footnote on page 13 of the Technical Support Document); c. regulations relating to meeting Maximum Achievable Control Technology (MACT) requirements; d. regulations relating to meeting New Source Performance Standards (NSPS), Prevention of Significant Deterioration (PSD) requirements, or Lowest Achievable Emission Rate (LAER) requirements; and/or e. requirements arising from the Indiana State Implementation Plan (SIP)?

b. (RHAMC) Can BP continue to use credits if it must reduce emissions as a result of federal or state regulatory standards that are issued during the balance of the contemporaneous period? For example, the Petroleum Refinery MACT is now in the process of being amended to address residual risk (see 72 FR 50716, September 4,

2007). There are also recently proposed regulations establishing new Standards of Performance for Petroleum Refineries (see 72 FR 27178, May 14, 2007). These regulatory initiatives could result in requirements mandating emission reductions BP is now "volunteering" to do in order to create credits. Will these credits survive new regulatory initiatives enacted during the contemporaneous period?

c. (Save the Dunes Council) Some of the reductions were from projects years ago and we question if these reductions should be credited for years into the future.

Response:

IDEM believes that the reductions in emissions of all pollutants for which credits are claimed are available and are not otherwise required by NSPS, MACT or an administrative or judicial enforcement order or a consent decree (other than Consent Decree #96 CV 095RL dated1/18/2001, as described in the footnote on page 13 of the Technical Support Document).

The creditable emissions reductions are not otherwise required by PSD-BACT or LAER requirements, since none of the new or existing emissions units at this facility are subject to PSD-BACT or LAER.

For affected units that have baseline PM-10 emissions greater than the allowable PM-10 SIP limits under 326 IAC 6.8-2-6, the baseline emissions have been adjusted to the SIP limits for estimating the PM-10 emissions increases for these affected units.
IDEM does not have the authority to consider proposed federal regulatory requirements that may or may not be effective in the future for the evaluation of the netting analysis.

No change has been made as a result of this comment.

Technical Comment No. 4:

(Chicago and Illinois Attorney General) The specific concerns related to netting are as follows:

The analysis excludes the years 2005 and 2006 without an explanation. The application was filed in November 2007. The netting analysis must include recent data, but can go back up to 10 years. The baseline years could therefore be between 1997 and 2006. The base years used for the netting analysis submitted in this application include the period 1999-2004. There is no documentation as to why 2005 and 2006 were excluded from the netting analysis. Since the 2005 and 2006 emissions data is the most recent, it should be included in the netting analysis for an accurate and complete analysis.

Response:

Under 326 IAC 2-2 (PSD rules) and 326 IAC 2-3 (Emission Offset rules) "baseline actual emissions" are defined as follows:

For an existing emissions unit other than an electric utility steam generating unit, "baseline actual emissions" means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during ***any consecutive twenty-four (24) month period selected by the owner or operator within the ten (10) year period*** *immediately preceding either the date the owner or operator begins actual construction of the project or the date a complete permit application is received by the department for a permit required by this rule, except that the ten (10) year period shall not include any period earlier than November 15, 1990...****(emphasis added)***

Based on this definition, the Permittee has the exclusive authority to select the representative 24 month period that otherwise meet the requirements of this definition. IDEM has determined that it

is not necessary for the Permittee to submit baseline emissions from the 2005-2006 calendar years, since the Permittee chose to use baseline years (for all pollutants) from 1999 to 2004 only for the netting analysis.

Technical Comment No. 5:

A. (Chicago and Illinois Attorney General) In the netting analysis, past emissions were calculated using natural gas emission factors, even though refinery gas was the fuel most often burned historically. Many of the units have the capability of burning multiple fuels (natural gas, RFG, LPG). Emissions for netting must be based upon the fuel or fuels actually burned during the base year period. It appears that refinery gas was burned, however, emission estimates are based upon natural gas combustion emission factors, even though refinery gas often has the highest emission factor.

B. (Chicago and Illinois Attorney General) Future emissions also were calculated using natural gas emission factors, instead of considering all possible fuel sources. The future actual emissions analysis should take into account all possible fuels allowed in the permit. Failure to consider all fuels in the future actual case would require that the future case be limited to only those fuels that actually burned in the baseline period.

Response:

Since there are no specific AP-42 emission factors for combustion of refinery fuel gas, it is appropriate to use the AP-42 emission factors for natural gas for estimating the baseline emissions, unless site-specific stack test data is available. IDEM believes that the emission rate for the other regulated pollutants would be the same or slightly higher for refinery fuel gas combustion as compared to natural gas combustion. Based on that, IDEM believes that using natural gas as the basis for emissions in baseline calculations would then lead to a lower baseline estimate, which would be a conservative approach for the netting analysis. For some of the emissions units, the Permittee is required to install Continuous Emissions Monitors for measuring SO2, CO or NOx emissions to ensure compliance with the PSD minor limits. In addition, with regard to SO2 emission rates, the Permittee is required, under NSPS Subpart J, to monitor H2S concentration in the refinery fuel gas currently, and will be required, as part of the monitoring conditions of this permit, to monitor total reduced sulfur to ensure compliance with the 80 ppm limit for the refinery fuel gas. For emission units not equipped with CEMS, the Permittee is required to perform stack tests in order to verify the emission factors used in the netting analysis, as included in Section D.0 of the draft permit. The future allowable emissions for emission units capable of burning refinery fuel gas are based on emission limits and the fuel usage. IDEM believes that the performance tests included in Condition D.0.3 (as revised) are adequate to ensure compliance with the limitations on the emissions, irrespective of the fuel burned. (see Response to Technical Comment #42 for additional information related to changes to testing)

Technical Comment No. 6:

(Chicago and Illinois Attorney General) Netting Analysis: the calculation of future actual emissions appear to under-represent the maximum permitted operating capacity of many units. The ratings for many existing sources are set at levels well below the permitted capacities when making future actual emission calculations. Operating capacities during 2005-2007 should be reviewed to verify if projected values seem reasonable based upon actual levels through stack testing.

Response:

The Permittee has proposed, as part of the application for the OCC project, voluntary limitations on throughput, fuel usage, and firing rates, which are lower than the maximum capacity of these units. The draft permit included recordkeeping and reporting requirements for all new and existing

emission units that have such limitations. IDEM has determined that these requirements are adequate to ensure compliance with the emissions limitations included in the permit.

No change has been made as a result of this comment.

Technical Comment No. 7:

(Chicago and Illinois Attorney General) Stack tests are cited and the permit uses the results of these tests as emission factors, with incomplete data of which fuel was used during the tests. From the permit information provided, it is impossible to determine whether the emission factors from these stack tests have been properly applied. For example, if the stack test was conducted while burning natural gas, the emission factor is applicable to natural gas only, and vice versa.

Response:

The emission factors submitted by the Permittee (as included in the application certified by the Responsible Official) and used in the netting analysis are derived from three sources:

A. AP-42 (Fifth Edition)

B. Stack tests performed at BP-Whiting.

C. Design guarantees based on design specifications.

IDEM believes that the Permittee has adequately documented the source of the emission factors used in the netting analysis.

No change has been made as a result of this comment.

Technical Comment No. 8:

(Chicago and Illinois Attorney General)

a. The draft permit fails to adequately explain the asserted reduction in SO2 emissions. The emission calculations for SO2 for combustion show a 50% reduction in the sulfur content of the fuel. If the reduction is due to process modifications that will improve the quality of the refinery gas, this further emphasizes that the fuel being used and that will be used in the future is actually refinery gas, not natural gas.

b. The permit uses an emission factor for SO2 that underestimates the level of sulfur in the tar sands crude. H2S and reduced sulfur compounds will be emitted in higher amounts when the refinery processes tar sands crude, mostly from fugitive sources like tanks, valves, flanges, and the sulfur recovery plant. The permit does not adequately account for these additional sources of pollution.

Response:

Unless there is a condition in the permit that prohibits the use of any fuel other than natural gas at a specific emission unit, the Permittee is allowed to use refinery fuel gas as a combustion fuel at BP's Whiting facility.

The SO2 emissions calculations were submitted as part of BP's application certified by the Responsible Official. In order to demonstrate compliance with the PSD minor limits on SO2 emissions from the new and existing emission units, the Permittee is required to install and operate CEMs to monitor total reduce sulfur (TRS) and H2S, and keep monthly records of the

SO2 emissions from these units. The Permittee is also required to submit certified quarterly report forms to demonstrate compliance with the SO2 emissions limitations. IDEM believes that the monitoring and recordkeeping requirements in the permit are adequate for demonstrating compliance with the emission limitations in the permit. In addition, with regard to RFG, see Response to Technical Comment #5 above.

In addition, the capacity of the refinery's sulfur recovery complex will increase by a factor of 3 (three) with the OCC project. The sulfur content of the RFG will be reduced through vapor recovery, amine treatment, and new claus trains, which are specifically designed to remove sulfur from fuel gas streams prior to combustion. Although Canadian crude may contain a higher sulfur content than certain other crudes currently processed by the refinery, the overall total sulfur content in refinery fuel gas combusted in the refinery will be reduced by virtue of these enhanced and additional controls.

No change has been made as a result of this comment.

Technical Comment No. 9 (Chicago and Illinois Attorney General)**:**

Data provided indicates that reductions in sulfuric acid mist will be based upon continuous emission monitoring (CEM) for SO2. However, the method of quantifying sulfuric acid mist emissions should be documented, especially for those cases where sources are being shutdown and credit taken for emission reductions.

Response:

The methodology for the calculation for baseline and future sulfuric acid mist emissions were included in Table C.8 of the Technical Support Document for the draft permit, as submitted by the Permittee and certified by the Responsible Official. The methodology is summarized below:

Combustion emissions are assumed to include some amount of SO3 which can react with water vapor in the stack to produce sulfuric acid mist. H2SO4 mist emissions were conservatively estimated assuming 3% of the SO2 emitted is in the form of SO3. The baseline SO2 emissions are based on source-specific H2S (hydrogen Sulfide) CEMs data, and TRS (Total Reduced Sulfur) CEMs data wherever available. This is true for all existing units, including those scheduled to be shutdown for creditable emission reductions.

Technical Comment No. 10 (Chicago and Illinois Attorney General)**:**

The permit uses questionable emission factors for mercury. In all cases, BP has used API/WSPA emission factors for mercury emissions. AP-42 contains higher mercury emission factors for many units, based on the combustion of natural gas. There is no supporting documentation for the justification of using API/WSPA. This appears to be contrary to IDEM's Non Rule Policy on the use of AP-42 emission factors.

Response:

According to the application submitted by the Permittee and certified by the Responsible Official, the emission factor for mercury for baseline and future combustion calculations are based on industry-specific mercury emission factors developed by API/WSPA [American Petroleum Institute/Western States Petroleum Association]. These emission factors for mercury emissions from fuel gas combustion are based on a study taking data from specific units in the refining industry and are therefore believed to be the most representative emission factors available. Using EPA's hierarchy of emission factors, the API emission factor for Hg is preferred due to being established more recently and proven during recent testing at several refineries. The

baseline established using this emission factor does not affect the permit level determination as the same limit is used going forward in the revised permit.

Technical Comment No. 11 (Chicago and Illinois Attorney General)**:**

A dispersion analysis is needed to understand the full impact of this project. The project's impact on air quality should be quantified by air quality dispersion modeling rather than quantified by an analysis of changes in emissions. Both the PSD and the Emission Offset rules include requirements to use dispersion computer modeling to address the air quality impact of the modification and to compare the impact to various standards established by the respective rules. There are a number of factors such as stack heights and locations that can influence the dispersion characteristics of the emissions and the overall air quality impact of the project. During the course of the project, emissions may, in fact, be significantly higher than the baseline emissions. The impact on air quality during these periods has not been addressed in the draft permit documents.

Response:

Based on the netting analysis submitted by the Permittee, the OCC project is minor under Prevention of Significant Deterioration (PSD), Emission Offset (EO), and Nonattainment NSR rules under 326 IAC 2-2, 326 IAC 2-3, and 326 IAC 2-1.1-5. The air quality modeling required under the PSD and EO rules do not apply to this project because of the minor status of this project.

The following requirement that is included in the permit in Condition D.0.1 addresses the issue of project increases and decreases. Since the Permittee is required to demonstrate that the increases in emissions remain below significant levels under PSD and EO rules, IDEM does not have the authority to require air quality modeling analysis during the interim period of this phased construction project.

> *Following the issuance of SPM No. 089-25488-00453 the Permittee shall determine, on a monthly basis, the increase in emissions of SO2, NOx, PM, PM 10, CO, Pb, Be, Hg, H2SO4 and VOC from all new, modified and existing affected emission units at this source, and shall demonstrate, that the net emissions increases from this project remain below significant levels per twelve (12) consecutive month period beginning with issuance of SPM No. 089-25488-00453, in accordance with the following:...*

No change has been made as a result of this comment.

Technical Comment No. 12 (Chicago and Illinois Attorney General)**:**

The permit does not comply with the current requirements in Indiana's SIP. It instead incorporates proposed preliminary revisions to the SIP that have not been approved by EPA.

Response:

See Response to "EPA Comment No. 2".

Technical Comment No. 13 (Chicago and Illinois Attorney General)**:**

Heavy crude data - To evaluate the potential to emit from various process units in the refinery after the completion of construction of the OCC project, it is necessary to have a complete analysis of the Canadian Extra Heavy Oil including its physical properties such as ash content, viscosity, viscosity index, boiling point, and vapor pressure among others.

Response:

The emissions estimates for various emission units at this facility were included in the application submitted by the Permittee and certified by the Responsible Official. These emissions estimates were based on a significant amount of research and evaluation, including evaluations of CXHO which BP currently processes at the Whiting facility. The Whiting plant currently processes approximately 20-25% CXHO, and so the information provided is based on BP's evaluation of this crude stock. In addition, IDEM believes that the compliance determination and monitoring requirements, and the associated recordkeeping and reporting requirements, included in this permit are adequate to demonstrate compliance with the PSD, EO, and NA-NSR minor limits included in the permit.

No change has been made as a result of this comment.

Technical Comment No. 14 (Chicago and Illinois Attorney General)**:**

Insufficient flaring data - Section D.35 does not contain adequate data to evaluate the sufficiency of the engineering design. The footnote on page 1 states that the GOHT and South flare are equipped with a flare gas recovery system, however the maximum capacity has not been determined.

Response:

The flare gas recovery system is designed to capture and recycle emissions from the associated emission units. These emissions are recovered and utilized in the refinery fuel gas system. BP has designed a recovery system with sufficient capacity to collect all emissions associated with routine or normal flaring events, including routine maintenance and repair periods. In addition, the flare gas recovery system is equipped with a back-up compressor of the same capacity as the primary compressor.

See response to Technical Comment #1 for further information regarding flaring.

Technical Comment No. 15:

a. Susan MiHalo (Ogden Dunes, IN) The permit should contain a compliance schedule to address the violations included in U.S. EPA's Notice of Violation and Finding of Violation sent to BP on November 29, 2007.

b. (RHAMC) A fundamental purpose of the Title V permitting program is to ensure that regulated entities comply with requirements in the Clean Air Act. Under 40 C.F.R. § 70.1(b) and Clean Air Act § 504(a), each regulated major source must obtain a permit that "assures compliance by the source with all applicable requirements." A Title V permit applicant must disclose its compliance status and either certify compliance or enter into an enforceable schedule of compliance to remedy violations. 42 U.S.C. § 7661b(b); 40 C.F.R. § 70.5(c)(8-9).

   Mindful of these requirements, on what basis does IDEM assert that a schedule of compliance or compliance plan is not required as part of issuing the Title 5 permit in lights of: a. the Finding and Notice of Violation issued by U.S. EPA Region 5 to BP Products North America, Inc., Whiting, Indiana on or about November 29, 2007, and, b. the Finding and Notice of Violation issued by U.S. EPA Region 5 to BP Products North America, Inc., Whiting, Indiana on or about January 25, 2007 (EPA-07-IN-03)?

   The operating permits must include a compliance schedule remedying these violations. 40 CFR § 70.5(c)(8)(iii)(C). Pursuant to this section, if a facility is in violation of an

applicable requirement at the time of permit issuance, the facility's permit must include a schedule leading to compliance with that requirement. The only exemption is if the reported violation has been corrected prior to permit issuance. Applicable requirements include, among others, the requirement to comply with state implementation plan ("SIP") requirements. *See* 40 C.F.R. § 70.2. If a facility is in violation of an applicable requirement at the time that it receives an operating permit, the facility's permit must include a compliance schedule. *See* 40 C.F.R. § 70.5(c)(8)(iii)(C). The compliance schedule must contain "an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the source will be in noncompliance at the time of permit issuance." *See* 40 C.F.R. § 70.5(c)(8)(iii)(C).

c. (Save the Dunes Council) In November 2007, the U.S. EPA issued a Notice of Violation to the BP whiting facility for numerous violations of the Clean Air Act. The Commenter understands that the Clean Air Act prevents issuing a new operating permit until a compliance schedule is ordered that will rectify these violations.

d. (Chicago and Illinois Attorney General) The Attorney General's Office received from the U.S. EPA a copy of their Notice of Violation and Finding of Violation sent to BP on November 29, 2007. The permit should contain a compliance schedule to address these violations.

e. (NRDC Group) IDEM failed to require and include a schedule of compliance for the violations identified in the NOV issued to BP in connection with the Whiting Refinery. In addition, deviation reports concerning flaring submitted to IDEM indicate repeated violations of current flare emissions limitations. Under Title V of the CAA and associated regulations, IDEM was required to mandate submission of a schedule of compliance addressing these violations, and to include it in the Project Title V permit modification. BP failed to submit the required schedule of compliance. IDEM must make a determination that BP's Title V permit application is incomplete, and require submission of a schedule of compliance, and the schedule of compliance must be incorporated into the permit.

Response:

See response to "EPA Comment No. 6".

Technical Comment No. 16 (RHAMC)**:**

In an earlier 2006 permit application, BP indicated there would be increases in CO such that PSD review would be triggered. We have reviewed the 2006 and 2007 permit applications at some length to determine the basis for the 2007 permit application's much lower calculation of projected CO emissions. Is it accurate to conclude that the 2007 permit application does not include any CO emission control equipment additional to that provided in the 2006 permit application?

Response:

There are no CO emission controls proposed in either application. The November 2007 application was a completely new application with significant changes to the original engineering and design of the OCC project. This included more specific emissions information related to vendor guaranteed emission rates for certain units, and the replacement of additional units, not originally proposed, with more modern, lower emitting units. Therefore, given that the pending permit is based exclusively on the information provided in the November 2007 application and the associated project design, it is not appropriate to compare the pending permit to the earlier application received in 2006.

No change has been made as a result of this comment.

Technical Comment No. 17:

a. (RHAMC) The most recent permit application contains some emission rates that are significantly lower than those given in the earlier, 2006 permit application. Specifically, Table 3.2 of the 2007 permit application relies on a CO emission rates of 0.04 lbs/MMBTU for Unit B-601A; the earlier permit shows an emission rate for this unit of 0.05 lbs/MMBTU. Similarly, emission rates in the 2007 permit application for H-101, H-201-203, and HU1-HU2 are, respectively, 0.019, 0.019, and 0.015 lbs/MMBTU while the emission rates for these same units in the earlier permit application were all 0.04 lbs/MMBTU. What is the basis for this change in estimated emission rates from these units?

If the lower CO emission estimates reflect a recalculation rather than additional equipment controls, shouldn't the CO potential to emit be established at the higher estimate? In answering this question, please be mindful of the regulatory definition of potential to emit:

The maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of fuel combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.
40 C.F.R. Sections 52.21(b)(4), 51.165(a)(1)(iii), 51.166(b)(4).

b. (Save the Dunes Council) Commenter is concerned about the Emissions Inventory in the application and urges IDEM to take a closer look at the total emissions. The first application showed a significant increase in one regulated pollutant - CO, by 420 tons per year. The current application shows a reduction in that and most regulated pollutants. However, some of the reductions were from projects years ago and the Commenter questions if these reductions should be credited for increases years into the future.

Response:

a. As explained in "Response to Technical Comment No. 16", there is no basis for comparing the details of the 2006 application with the permit application received in 2007. The PSD and EO minor limits on emission factors for all heaters were made practically enforceable in the permit by either including a requirement for conducting stack tests, or by requiring a use of a CO CEMs. IDEM has determined that it is irrelevant that the CO potential to emit should be based on the higher estimate included in the 2006 application, because the practically enforceable limitations included in the permit on the CO emission factors, along with the enforceable limitations on fuel usages at these heaters, are adequate to demonstrate compliance with the PSD and EO minor limits included in the permit.

b. Pursuant to 326 IAC 2-2 and 326 IAC 2-3, the contemporaneous period is defined as follows:

An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between the following:

(A) The date five (5) years before construction of the particular change commences.
(B) The date that the increase from the particular change occurs.

Based on the above, IDEM has determined that past emissions reductions that occurred within the contemporaneous period from the commencement of the OCC project are creditable emissions reductions.

No change has been made as a result of this comment.

Technical Comment No. 18:

Several Commenters expressed concerns related to the emissions and netting calculations included in this permit, and the permit level determination. Their comments are summarized below:

a. (RHAMC) For the purpose of assessing the actual impact of BP's proposed project on public health and the environment, it is critical that we can compare actual emissions before the modifications to projected emissions during and after those modifications. While the permit contains a list of 2003 actual emissions in tons per year from the entire facility (p. 4 of TSD), there is no comparable table that quantifies estimated actual emissions in tons per year for each year between 2003 and 2012, when the modifications/shutdowns/new units identified in the permit have all been put into place. While the permit's focus on netting, "contemporaneous" credits and consent decree reductions may be of import in terms of legally applicable emission standards, it is the true change in air emissions before, during and after this project that will affect the health and environment that RHAMC is concerned about.

IDEM's permit should require BP to provide information describing actual emissions for every affected individual emission unit and source identified in the permit, along with annual projections of increases/decreases from that unit, for the entire contemporaneous period, for each pollutant. This information is necessary to ensure that permit terms and conditions are practically enforceable.

IDEM's permit should provide for the availability on its website of BP's annual and/or semi-annual reports on actual emissions during this period so that the public can determine whether actual emissions are as projected in the draft permits.

b. BP's actual emissions show:

PM emissions in tons per year:
2006 (actual): 544
2011 (projected): 658

This is 114 tons per year increase. It is my understanding that the limit for being considered a major modification is 15 tons per year. It is also my understanding that BP is planning on using their emission credits to decrease that number by 107.3. This leaves them with a net increase of 6.7. We all know that without use of the credits, BP would be considered a major modification and subject to stricter emission controls. I do not want my children exposed to 114 additional tons per year. These emission credits are an administrative scheme and we all know it. Please place stricter restrictions on BP to the Clean Air standards and do not allow them to be grandfathered in to lesser standards.

c. (Save the Dunes Council) The Commenter is unclear about the increases in PM and SO2 emissions. In their "Whiting Modernization Plan Update (February 2008), the company claims that there will be an increase of 114 tons of PM10 and SO2 will increase by 211 tons per year. Other information in the TSD has other numbers. What is the correct amount of increases for these regulated pollutants? How does that compare with the statements that there are no increases in regulated pollutants?

d. (Sauk-Calumet Sierra) The Commenter is concerned about increases in particulate matter, sulfur dioxide, hydrogen sulfide, lead and greenhouse gases. BP expects its expansion project to increase the facility's carbon dioxide emissions by 30 to 50 percent although carbon dioxide is not regulated under the permit.

e. (Daniel Grelck, Lowell, IN) Why is IDEM permitting BP to discharge 24% more lead emissions? When asked about the added lead exposure, the IDEM official stated that there was no lead increase. He later retracted his statement. BP said there would be an increase. Has IDEM read or even understood what is in the entire permit?

f. (Bryant Mitol, speaker) There is going to be a significant (25 - 30%) increase in lead, which is one of the most dangerous neurotoxins in this country.

g. (Kim Ferraro, Legal Environmental Aid Foundation) The Clean Air Act certainly does not prohibit BP from expanding its facility; however, the Clean Air Act does require that all of the Whiting Refinery's emissions be included in the netting analysis, including emissions from the three new flares that will be built as part of the refinery's expansion project. If these emissions are included in the calculations, the project will correctly be deemed a major modification subject to more stringent requirements. The permit should be issued with appropriate limits, including Best Available Control Technology (BACT), and Lowest achievable Emission Rate (LAER), as required for all major modifications of existing sources of air pollution under the Clean Air Act.

h. (Ann Alexander, NRDC) The pollution reductions in CO being claimed (compared to the 2006 application) are not being achieved by actually controlling emissions, but by simply not counting them at all. In short, they are not real.

i. (Larry Silvestri, speaker) Emissions of benzene, pyrene, cyanide, mercury, are not included in this permit. This permit does not quantify 15 or 20 dioxins. Insignificant activities include annual emissions of 40 tons per year of SO2, nitrous oxide, carbon dioxide and lead and other unnamed hazardous air pollutants.

Response:

The emissions of CO2 and other greenhouse gases are addressed in the response to "Technical Comment No. 34". The flare emissions are addressed in the response to "Technical Comment No. 1".

The PM, PM10, Pb, H2S and SO2 emissions calculations for the OCC project are based on the calculations submitted by the Permittee (certified by the Responsible Official) as included in Appendix C and E to this Addendum to the Technical Support Document. The netting analysis is summarized below. This source is a major source of HAPs and is subject to several NESHAPs (National Emission Standards for Hazardous Air Pollutants) as included in the E sections of the permit. IDEM does not believe that enumerating the emissions of individual HAPs is necessary as part of this permit. Lead and mercury emissions were included in Section C and E of the permit, and show a decrease in the netting analysis submitted by the Permittee (and certified by the Responsible Official).

<u>PM and PM10 Netting Analysis:</u>
The PM and PM10 emissions from the CXHO project are calculated from the following:

The net emissions increase of PM/PM10 from this project is the amount by which the sum of the following exceeds zero:

(a) The increase in PM/PM10 emissions from its baseline year (Calculated from the average of 24 consecutive month period within the ten year period preceding the start of construction of the project) from this proposed project:

PM (tons per year)	PM10 (tons per year)
138.9	216.7

(b) Voluntary enforceable reduction by BP in PM/PM10 emissions from its existing operation during the contemporaneous period (Any baseline year, allowed by USEPA and IDEM, within 5 year preceding the start of construction and up to start of the operation of the new equipment). This is allowed by the federal and Indiana PSD (Prevention of Significant Deterioration) rules.

Net effect is the reduction of more than 200 tons per year of PM and PM10 as shown in the following table. These reductions are made enforceable in the permit. The Permittee also is required to keep emissions records and submit quarterly reports to demonstrate compliance with all emissions limitations included in the permit.

	PM	**PM10**
Project Emissions Increase	138.9	216.7
Net Emissions Increase (NEI) with Past Contemporaneous Increases and Decreases	-17.5	60.5
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases related to CXHO (phased construction)	-204.2	-5.0
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases – non-CXHO (phased shutdown)	-281.9	-1.6
Total for Modification after Netting	-281.9	-41.6
Significant Level or Major Source Threshold	25	15

SO2 Netting Analysis

Pursuant to Consent Decree (United States et. al. vs. BP Exploration and Oil, et. al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL), 10% of SO2 netting credits generated by the cessation of oil burning at heaters and boilers and reduction of SO2 concentration at the outlet of FCU600 can be used to offset emissions increases only at units that meet the definition of "Lower Sulfur Fuel Units" and "Netting Offset Generating Units". These SO2 credits cannot be used to offset increases at other emission units, including flares and Tail Gas Units (COT1 and COT2). Table C.82a shows the detailed calculations for SO2 netting analysis conducted in accordance with the requirements of the Consent Decree. The summary of the SO2 netting analysis is as follows:

Total increases in SO2 emissions at "Low Sulfur Fuel Units" = 107.3 tpy
Total available SO2 credits from cessation of fuel oil burning = 269.4 tpy

Total increases in SO2 emissions at other "Netting/Offset Generating Units" = 149.5 tpy
Total available SO2 credits from FCU 600 consent decree reduction = 160.9 tpy

Total increases in SO2 emissions from other emission units = 203.3 tpy
Total available non-consent decree related SO2 credits = 230.1 tpy

The total available SO2 credits available as offsets in all three categories exceed the SO2 emissions increases from new, modified, affected, and future contemporaneous non-CXHO related units. Therefore, the SO2 emissions increases do not exceed the significant level for SO2.

There is no guarantee that if this project was reviewed as a major source for PSD, there will be any reduction in emissions or there will be any economically and technologically feasible controls applicable to the emissions units at this source.

H2S and Pb Netting Analysis

The netting analysis submitted by the Permittee (and certified by the Responsible Official) shows a reduction in emissions of H2S, and lead (Pb) as shown below (in tons per year):

	Pb	**H2S**
Project Emissions Increase	0.041	14.8
Net Emissions Increase (NEI) with Past Contemporaneous Increases and Decreases	-0.02	-5.3
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases related to CXHO (phased construction)	-0.02	-15.9
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases – non-CXHO (phased shutdown)	-0.02	-15.9
Total for Modification after Netting	-0.02	-15.9
Significant Level or Major Source Threshold	0.6	0.6

No change has been made as a result of this comment.

Technical Comment No. 19 (RHAMC)**:**

How will IDEM ensure that during this contemporaneous period there will not be an emission increase without a corresponding decrease, such that the facility does not emit a pollutant above the significance level at any time?

Response:

The following requirement that is included in the permit in Condition D.0.1 addresses the issue of project increases and decreases during the interim period from the commencement of construction to the startup of Coker #2 (which signifies the end of the CXHO project). Since the Permittee is required to demonstrate that the increases in emissions remain below significant levels under PSD and EO rules, IDEM does not have the authority to require air quality modeling analysis during the interim period of this phased construction project.

> *Following the issuance of SPM No. 089-25488-00453 the Permittee shall determine, on a monthly basis, the increase in emissions of SO2, NOx, PM, PM 10, CO, Pb, Be, Hg, H2SO4 and VOC from all new, modified and existing affected emission units at this source, and shall demonstrate, that the net emissions increases from this project remain below significant levels per twelve (12) consecutive month period beginning with issuance of SPM No. 089-25488-00453, in accordance with the following:...*

No change has been made as a result of this comment.

Technical Comment No. 20 (RHAMC)**:**

Does the netting exercise include every emission unit and source at the refinery? If not, what units and sources are not included? How will IDEM and/or BP monitor these units to ensure that changes at the refinery, including increased production, will not lead to emission increases at these units?

Response:

The emission units included in the netting analysis submitted by the Permittee, and evaluated by IDEM, include new units, modified units and affected units that are involved in processing of the Canadian crude. Based on its evaluation, IDEM has no reason to believe that other emission units, that are affected by the project, were excluded from the netting analysis. IDEM has included comprehensive monitoring, recordkeeping, and reporting requirements in the permit which are adequate to ensure compliance with the emissions limitations in the permit and to ensure that the net increases from the the OCC project remain below the significant levels. In addition, IDEM has inspectors stationed in northwest Indiana responsible for monitoring the operations at the BP refinery. One of their responsibilities will be to conduct inspections at the plant to verify compliance with the requirements of this permit.

No change has been made as a result of this comment.

Technical Comment No. 21 (RHAMC)**:**

At the completion of its construction/modification activities, will BP be allowed to sell emission credits resulting from the reductions it anticipates?

Response:

Emissions reductions used as creditable decreases in the netting evaluation, and made enforceable through this permit, will not be available for sale. Any emission reductions that are above and beyond the reductions required as part of this netting analysis, may be available for sale, but that beyond the scope of this permitting action.

Technical Comment No. 22 (RHAMC)**:**

When will the credits from the 2001 Consent Decree emission reductions expire? What if these credits expire before BP constructs the new/modified emission units? If so, how can the emissions from those new/modified units be offset in any way by the consent decree “credits”?

By way of background to this question, BP is taking significant credits (for SO2 and PM) from the Consent Decree excess reduction. In Table C.82 of the 2007 permit application, there is a list of “Past Contemporaneous Changes.” [Note: The draft permit uses Table 82 for everything but SO2 and Table 82a for SO2; the dates in the application Table 82 are not included in the permit Table 82.] The largest of these, at least for SO2 and PM, is from the 2001 Consent Decree and that change is described as “effective 6/01/03.” Under U.S.EPA’s new source rules, the ten-year

"lookback rule" for baseline emission is measured from the date of the permit application. *See* 67 Fed. Reg. 80195 (12/31/2002). But the rules indicate that credits for emission reductions during the "contemporaneous period" must have occurred between the date five years before construction of the change and the date that the increase from the change occurs.

Response:

The emission credits from the 2001 Consent Decree emissions reductions relevant to this project would expire on June 1, 2008 unless BP commences construction prior to that date. Under the major NSR regulations, commence construction refers to the project and not individual emission units. Therefore, provided construction commences on any part the project prior to June 1, 2008, even if all the modifications and new units are not fully constructed, the credits will not expire.

Based on the calculations included in the application, submitted by the Permittee and certified by the Responsible Official, IDEM and the US EPA have determined that the credits used by BP for the OCC project, some of which were generated by complying with the consent decree, are available for use in this netting analysis. Only these creditable reductions are included as part of this netting analysis. IDEM and the US EPA have coordinated on this issue and both agencies agree that the credits being utilized are consistent with the allowances established in this Federal Consent Decree.

Technical Comment No. 23 (RHAMC):

The permits rely to a great extent on CEM results for reviewing the source's compliance status. Indeed, emission testing appears to be limited to once every five years (Section D.0.3). As the permit is unclear about where CEMs are required, can IDEM provide a complete list of units that are required to have CEMs? For those units that are not monitored by CEMs, can IDEM provide a description of how it will verify emission rates and total emissions?

Response:

Sections D.1 through D.45 in the permit already include requirements for the operation of CEMs wherever the Permittee is required to utilize CEMs for demonstrating compliance with emission limitations. For emission units that are not equipped with CEMs, IDEM has determined that the testing requirements in Section D.0.3 are adequate for demonstrating compliance with the requirements of the permit. To evaluate these requirements, you can refer to the Compliance Determination Section of the respective D sections of the permit and the Compliance Monitoring and Determination section of the Technical Support Document.

Technical Comment No. 24 (RHAMC)**:**

What steps has IDEM taken to ensure BP has not commenced construction activity before a construction permit has issued? What are the results of any investigations?

Response:

IDEM has no knowledge of any construction activities related to the OCC project, for which prior construction approval would be required. IDEM routinely inspects this source to verify compliance with its permit and all applicable State and Federal requirements. If there was an indication during one of these inspections that construction had commenced it would be documented and the appropriate response would be taken by IDEM.

Technical Comment No. 25 (RHAMC)**:**

On what basis does IDEM assert that the actual technology employed in the new decoking unit is not relevant to IDEM's review of unit emissions and emission controls, as claimed by an IDEM representative during the Information Session on March 14, 2008?

Response:

The requirements included in the draft permit are based on the design specifications submitted by the Permittee. IDEM does not have the authority to dictate actual technology employed in the new decoking unit or any other process units involved in the OCC project. IDEM is obligated by regulation to evaluate the project as proposed by the applicant and determine if the project is capable of meeting all applicable State and Federal requirements. The method by which the source produces it respective products is not relevant to our evaluation.

Technical Comment No. 26 (RHAMC)**:**

There are three new flares listed in the permit: the GOHT flare, the South Flare and the HU flare. There is also reference in the 2007 permit application to the "VRU flare." BP asserts in its permit application that the new flares will have a gas recovery system so that no emissions will be released unless there is a problem at the plant. The permit does estimate a very small amount of emissions from the flares based on an estimate of those emergencies. Based on experiences at other comparable refineries, will the flare gas recovery system operate as BP claims, and are the estimates of the amount of emissions comparable to other refineries?

Are there any limits on emissions from the flares during periods when the gas recovery system is not functioning properly? How will these emissions be controlled and monitored?

Response:

Please see response to "Technical Comment No. 1".

Technical Comment No. 27 (RHAMC)**:**

Are fugitive emissions from the off-gassing of sludge that is a byproduct of new production processes included in emission estimates?

Response:

According to the application submitted by the Permittee and certified by the Responsible Official, the project includes two new processes that involve sludge handling. These include the brine treatment system and a new thermal desorption unit. The emissions from these units were included in the overall project emission calculations.

In regards to the off site shipment of waste materials, the OCC project will result in a decrease of waste generated. The reduction will be achieved by the replacement of the existing coke yard operation with an enclosed coke handling system, the installation of the brine treatment system to remove oil and solids from a wastewater stream before it enters the sewer system and the shutdown of a treating process that contains leaded catalyst and clay.

Technical Comment No. 28 (RHAMC)**:**

Are increased vehicle emissions related to the proposed facility construction and modification activities included in emission estimates? Does the construction permit include emission estimates related to the release of volatiles from painting and coating surfaces on new units?

Response:

According to the application submitted by the Permittee and certified by the Responsible Official, all fugitive emissions from emission units and production operations have been included in the netting analysis. Emissions generated from construction activities related to the project are not regulated.

Technical Comment No. 29 (RHAMC):

If this permit were being issued under PSD or LAER requirements, would IDEM have a basis to impose additional measures beyond those strictly mandated by NSPS? For hazardous air pollutants, doesn't IDEM have the legal authority to develop facility specific MACT standards?

Response:

There is no guarantee that if this project was reviewed as a major modification under PSD or EO, additional controls would be determined to be economically and/or technologically feasible for the emissions units modified or added at this source. Additional evaluation would be necessary to determine what BACT (Best Available Control Technology) or LAER (Lowest Achievable Emission Rate) would be for this project. However, IDEM does not have the authority to issue a permit imposing BACT or LAER requirements for a project that is deemed minor under 326 IAC 2-2 (PSD), 326 IAC 2-3 (EO), and 326 IAC 2-1.1-5 (NA NSR). IDEM has determined that this project is minor under these regulations and therefore it has not triggered BACT and/or LAER, so no additional evaluation is necessary.

The emission units at this source are already subject to several MACT standards which are identified in Sections E. 1 through E.26 of the permit (along with NSPS requirements). IDEM would only establish a facility specific MACT standard if no MACT standard had been promulgated for the respective operation. In this case, the units involved are already subject to MACT Standards that are effective or have been promulgated by the US EPA.

No change has been made as a result of this comment.

Technical Comment No. 30 (RHAMC)**:**

There are several, overlapping permitting activities for the BP facility, for example, the permit for the asphalt plant (#089-24068-00453), the tank-cleaning facilities (#089-6741-00453) and the diesel fuel production plant (#089-24410-00453). Will emissions from those plants change as a result of the changes to the refinery? Does the permit for the refinery modification include any credits for changes at the asphalt plant, diesel fuel plant or tank-cleaning facility?

Response:

The increases in emissions from the asphalt infrastructure project (permit no. 089-24068-00453), the tank sludge cleaning project (permit no. 089-24258-00453) are included in the netting analysis as shown in Table C.82 of Appendix C of the Technical Support Document as well in Table C.82 in Appendix C of the Addendum to the Technical Support Document. The permit numbers cited by the Commenter are in part erroneous: the tank sludge cleaning project was permitted in source modification no. 089-24258-00453, and incorporated into the Part 70 permit through permit modification no. 089-24410-00453. These source and permit modifications also included some diesel-fired emissions units, and the emissions from the entire project are included the netting analysis. Permit number 089-6741-00453 is the Part 70 permit number, and does not include the tank cleaning operation.

Technical Comment No. 31:

It would be helpful if IDEM would include details on the amount of emissions allowed during upset events and startup, shutdown, and malfunctions before and after the permit modification. This information should include carbon monoxide, nitrogen oxides, sulfur dioxide, VOCs, particulate matter, mercury and CO2.

In addition, the public needs more details on BP's plans to implement projects such as installation and operation of continuous ambient air quality monitoring stations around the refinery, enhanced street sweeping of roads around the refinery, and particulate matter controls on refinery trucks. If the planned modifications would affect the wastewater treatment system or pollutant discharges to Lake Michigan, additional details on these impacts must be explained in detail.

Response:

Ambient air quality monitoring is a requirement of the PSD permitting program [40 CFR 52.21(m)]. Since the OCC project results in a net decrease in emissions of criteria pollutants, and therefore does not trigger PSD permitting requirements, IDEM has determined that the installation of ambient air quality monitoring stations is not required for this project.

The OCC project will result in a decrease in fugitive dust particulate matter emissions. The current method of shipping coke offsite in trucks will be eliminated. The OCC project includes replacement of the current coke handling operations with a system that will include enclosed conveyors, an enclosed storage area, as well as enclosed and/or controlled transfer points. The new coke handling system will load coke into rail cars, thus eliminating coke truck traffic into and out of the refinery. BP will also, as part of the OCC project, comply with the updated fugitive dust control plan attached to the permit.

Pollutant discharges to Lake Michigan are addressed in the previously issued water permit for the OCC project, issued by IDEM, Office of Water Quality. Office of Air Quality does not regulate pollutant discharges to Lake Michigan. Therefore, this comment will not be addressed as part of BP Whiting's air

Also see Technical Response #1 for information regarding how start-up, shutdown, and malfunctions were accounted for in this permit.

Technical Comment No. 32:

IDEM needs to provide the public with the amount of permitted emissions today for each pollutant from the entire site and the proposed permitted emissions after the project is completed, including CO2.

Response:

The permitted emissions for the entire BP refinery would be the summation of allowable and potential emissions from all units currently operating at the plant. Given that this project did not affect all units at the plant, the calculations necessary for this permit are not all inclusive. The calculations included with this permit are only those necessary to evaluate the project and make the necessary regulatory determinations. The information necessary to make these expanded calculations are available to the commenter and can be done by reviewing the current permit, which is available on IDEM's website, in its entirety.

The emissions for each regulated pollutant (except for CO2, which is addressed in Response to Technical Comment No. 4) from the entire site, after the project is completed, are provided in Appendix C and E of this Addendum to the Technical Support Document to draft permits no. 089-

25484-00453 and 089-25488-00453. The baseline emissions for each pollutant are also provided in Appendix C.

Technical Comment No. 33:

The following Commenters expressed the opinion that carbon dioxide (CO2) and other greenhouse gases should have been addressed by the permit: NRDC Group, Sauk Calumet Sierra, Save the Dunes Council, Councilman Mark Kalwinski (Hammond, IN), Susan Mihalo (Ogden Dunes, IN), Marian Byrnes (Chicago, IL), Gerry M. Weston (Chicago, IL), Kim Ferraro (Legal Environmental Aid Foundation), Daniel Grelck (Lowell, IN). Their comments are summarized below:

a. Indiana law and the Clean Air Act require the Permits to address the post-BACT emissions of greenhouse gases from the expansion. One effective way of doing so is to require BP to offset these emissions on at least a ratio of 2:1 on a carbon equivalent basis, under clear rules ensuring that the offsets are additional, verifiable, real, regionally-based, permanent, and legally and practically enforceable. We respectfully request that the draft permits not be issued in their current form, without such offsets or equivalent measures.

b. IDEM needs to provide the public with the amount of proposed CO2 emissions after the OCC project is completed. No public hearing testimony should be needed on the issue of CO2. Silent testimony is presented every day, all around the world, by dead and dying coral reefs, by drowning polar bears, by summer spells of unbearable heat and drought. Regulations IDEM is obligated to follow do not take these global disasters into account. But global warming conditions have far outrun the regulations, and it has become obvious that everything in our power should be done to curb any and all increases in CO2 emissions. IDEM regulations can and must be upgraded to prevent significant increases in CO2 emissions.

c. The project will cause a huge increase in CO2. The company estimates that there will be a 30-40% increase "currently projected to be in the range of 1.5-2 million tons per year" or as much as 4 billion pounds of this greenhouse gas. This must be reduced or mitigated and with the huge profits BP has registered, it is affordable. How is IDEM addressing CO2?

d. Methane gas is a potent greenhouse gas, 23 times stronger than CO2. Methane is present in many parts of the refinery, as a portion of the many different hydrocarbons present. Methane emissions were not evaluated as part of the Project despite the fact that operation of project components will definitely result in methane emissions. Methane emissions at refineries are often overlooked because they are frequently exempt from smog VOC regulations. Although methane is a type of volatile organic compound, it is often excluded from VOC definitions because methane was previously considered not to be a strong contributor to smog (although newer evidence shows that it IS a major contributor). However, exclusion for assessment as a smog precursor is no reason not to evaluate methane emissions as GHGs.

   Examples of sources of methane emissions at oil refineries include tanks and pressure relief devices, as well as emissions of uncombusted methane from combustion sources that are never perfectly efficient. Additionally, according to US EPA, the greenhouse gas N2O is a normal product of the combustion of fossil fuels (which oil refineries obviously combust in large volumes in order to produce gas, diesel, etc.):

   Mobile and stationary sources of fossil fuel combustion. N2O is a product of the reaction that occurs between nitrogen and oxygen during fossil fuel combustion. The volume

emitted varies with the fuel type, technology, or pollution control device used, as well as maintenance and operating practices.

All GHG increases as a result of the Project need to be assessed.

e. BP must at a minimum meet CAA requirements to assess the quantity of GHGs from the expansion and conduct BACT analysis for all refinery GHG sources. The expected increase in GHG emissions is greater than the PSD significance threshold, which is any emissions of each GHG. IDEM nonetheless failed to include BACT limits on increases in any of the GHGs expected from the expansion. Indeed, the Permits contain no GHG reduction commitments at all. This failure is in violation of the CAA, even more so following this year's U.S. Supreme Court ruling in Massachusetts v. EPA, 127 S.Ct. 1438, 1460 (2007), holding that CO2 and other greenhouse gases are "pollutants" under the CAA. The draft Permits must be revised to include such limits. In addition, under state law, GHG emissions that will occur after application of BACT must be offset to protect the public health.

The Permits may not issue without BACT limits and offsets for GHGs, and IDEM must declare BP's application incomplete until sufficient information to conduct BACT and offset analyses concerning GHGs is provided. BP must provide this information not only to comply with the requirements of the CAA, but to fulfill its public commitment to GHG emission reduction.

f. BP's failure to comply with these requirements, and to implement measures that will curtail GHG emissions from the Project, is particularly unfortunate in light of the Company's pronouncements concerning not only the importance of limiting GHG emissions that cause global warming, but also the availability of measures by which to do so at its refineries. Refineries including BP have recognized that greenhouse gases can be reduced at refineries. These reductions are available in particular through flare minimization, as included in the following statement made by a BP official at Stanford University more than 10 years ago:

"*Our carbon dioxide emissions result from burning hydrocarbon fuels to produce heat and power, from flaring feed and product gases, and directly from the process of separation or transformation. Now we want to go further. We have to continue to improve the efficiency with which we use energy...We have already taken some steps in the right direction. In Norway, for example, we've reduced flaring to less than 20% of 1991 levels, primarily as a result of very simple, low cost measures. The operation there is now close to the technical minimum flare rate which is dictated by safety considerations."*

g. The U.S. Supreme Court has held that CO2 is a CAA "Pollutant". The CAA PSD Provisions require BACT for each pollutant "subject to regulation". The significance level for CO2 and other greenhouse gases is any amount above zero. CO2 is currently regulated under the CAA Acid Rain provisions. CO2 is subject to further regulation under the CAA. A pollutant need not be specifically regulated by a Section 111 or 112 standard to be considered regulated. Under both Sections 111 and 202 of the CAA, CO2 can be regulated, and should be regulated.

h. On May 14, 2007, President Bush issued an Executive Order confirming the Supreme Court's ruling that USEPA can regulate greenhouse gases, including CO2, from motor vehicles, nonroad vehicles and nonroad engines under the Clean Air Act.21 The Executive Order directs USEPA to coordinate with other federal agencies in undertaking such regulatory action. The President's action indicates the Chief Executive is also of the opinion that carbon dioxide is subject to regulation under the Clean Air Act.

i. Other greenhouse gases such as methane and nitrous oxide are also subject to regulation.

j. The main sources of GHGs from refineries are stationary combustion, FCCU catalyst regeneration, and hydrogen process vent. Id. Numerous opportunities exist for reduction of GHGs from these and other sources. A useful starting point are the GHG mitigation measures from the Final Environmental Impact Report for the Chevron Energy and Hydrogen Renewal Project in Richmond, California (attached as Exhibit 14).23 A list of measures relevant to the Whiting Refinery is as follows:

- Engage energy efficiency engineers to conduct a thorough audit of fuel, electricity and natural gas use at the Refinery to identify potential energy savings and energy efficiency improvements, and implement those feasible measures identified.
- Replace stationary, non-emergency diesel internal combustion engines.
- Retrofit or replace old process heaters to use new high efficiency burners, oxyfuel (use of oxygen instead of air), advanced controls, and/or more heat recovery
- Add/improve heat exchangers.
- Replace existing CoGens with higher-efficiency units, or add CoGen units.
- Replace stationary, non-emergency internal combustion engines with high efficiency electric motors. Implement process efficiencies (e.g., control fouling in crude unit preheater train).
- Initiate carbon sequestration, capture and export.
- Any reduction measures recommended by the state agency for refineries.

To the extent that these measures have not or are not being conducted at the refinery or as a part of the expansion project, they should be considered in the required BACT analyses for GHGs, along with any other identified control options. Such audits, retrofits and equipment installations can provide much-needed jobs to the Indiana economy.

k. The permit may not be issued unless greenhouse gases are limited sufficiently to protect human health. Indiana law prohibits the issuance of a permit that is not "protective of public health". See 326 IAC 2-1.1-5. This prohibition is independent of the requirement that permits ensure compliance with ambient air quality standards, PSD increments, and all other applicable air pollution control rules.

Given the relative difficulty in controlling GHGs from refineries due to the many and dispersed sources of GHGs, the Whiting refinery is likely to result in a significant volume of GHG emissions even after imposition of BACT. The public health threat associated with these climate change-causing GHGs is well documented. Regional concerns from global warming are presented in the U.S. Global Change Research Program's report entitled *Climate Change Impacts on the United States: The Potential Consequences of Climate Variability and Change* (*National Assessment*). The report was authored by scientists from the U.S. Geological Survey, USDA Forest Service, and numerous universities across the nation. According to the report, the Midwest is likely to face grave problems in terms of water quantity and quality due to drought and increasing heavy precipitation events, as well as dangerous increases in temperature and increases in respiratory disease due to increased pollution accompanying high temperatures.

l. (Sauk-Calumet Sierra) Tar sands crude will produce as much as three times greenhouse gas pollution as a regular barrel of oil. BP needs to adhere to more stringent pollution requirements if expansion proceeds. Pre-expansion standards are not sufficient. BP needs to at least quantify greenhouse gases that will be produced at the Whiting plant.

m. Greenhouse gas increases from the project will be large, and must be evaluated using top-down BACT analysis.

n. BP and IDEM failed to account for increased Greenhouse gases from the project and to conduct BACT analyses as required by the CAA.

Response:

Carbon dioxide (CO2) and other greenhouse gases including methane and N2O are not regulated pollutants. Consistent with the pronouncements of U.S. EPA on this subject, IDEM concludes that analysis is not required with respect to the projected emissions of CO2 from BP Whiting. Carbon dioxide is not currently subject to regulation under the CAA. The U.S. Supreme Court's decision in Massachusetts et al. v. Environmental Protection Agency et al., held merely that CO2 was a "pollutant" and that the U.S. EPA must decide whether, or how, it should be regulated. The Court did not conclude that CO2 is a pollutant subject to regulation. In determining which pollutants are subject to regulation under the CAA, IDEM has followed the U.S. EPA interpretation that the phrase "subject to regulation" means pollutants that are subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant.

The U.S. EPA has consistently determined that a pollutant such as CO2 is not a "pollutant subject to regulation" if the CAA did not require actual control of emissions of the pollutant. Moreover, this interpretation has been applied expressly to CO2. The U.S. EPA's interpretation has been laid out in several guidance memoranda. For example, in a memorandum dated April 26, 1993 from Lydia N. Wegman, of U.S. EPA's Office of Air Quality Planning and Standards, to U.S. EPA's Regional Air Directors, it is specifically considered whether CO2 was subject to regulation. The memorandum states that, although the 1990 amendments to the Clean Air Act included provisions addressing carbon dioxide and methane, "these requirements involve actions such as reporting and study, not actual control of emissions." The memorandum concluded, "if the results of these studies suggest the need for regulation, these pollutants could be reconsidered at that time for classification as pollutants subject to regulation under the Act." More recently, in 2002, the U.S. EPA substantially revised its New Source Review ("NSR") Program and promulgated revised rules on December 31, 2002. 67 Fed. Reg. 80290 (December 31, 2002). The revised rules substituted a new defined term, "regulated NSR pollutant" for the Act's phrase "pollutant subject to regulation." The phrase "regulated NSR pollutant" expressly includes only pollutants (or substances) (i) for which a national ambient air quality standard has been promulgated, (ii) that are subject to new source performance standards ("NSPS"), (iii) subject to a standard under the stratospheric ozone protection program of Title VI of the CAA, or (iv) that otherwise is subject to regulation under the Act (but generally excluding hazardous air pollutants). Indiana's definition is essentially a verbatim replication of the federal definition.

The first three categories of the definition are similar in one aspect – they all provide for the development of substantive emission standards of the specified pollutants through a formal and comprehensive rulemaking approach. Carbon dioxide is not regulated under any of these three programs. This regulatory framework brings clarity to the fourth, catchall category, any pollutant "otherwise subject to regulation under the Act" (excluding hazardous air pollutants regulated under Section 112 of the Act). When viewed with the other three categories, it becomes clear that U.S. EPA did not intend the fourth category to include pollutants for which the Act does not require substantive emission limitations. This approach is consistent with a canon of statutory interpretation known as *ejusdem generis,* which provides that, where general words of description follow an enumeration of persons or things described by words of a particular and specific meaning, the general words are not to be construed in their widest extent, but are to be understood as applying only to persons or things of the same class or kind as those specifically mentioned or listed. Moreover, when the U.S. EPA added the term "regulated NSR pollutant" to the NSR rules in 2002, it listed in the preamble to the rule all the pollutants that it believed were currently regulated under the CAA. This list did not include CO2.

The U.S. Environmental Appeals Board ("EAB") has expressly held that CO2 is not "subject to regulation." In *In re Inter-Power of New York, Inc.,* 5 E.A.D. 130, 151 (EAB 1994), the EAB held that the U.S. EPA was not required to conduct a BACT analysis for CO2 and hydrogen chloride because they were "unregulated pollutants." In *re Kawaihae Cogeneration Project,* 7 E.A.D. 107, 132 (EAB 1997) the EAB again reviewed whether the U.S. EPA should have included BACT limits for CO2. The EAB held that no limits were necessary because CO2 was not considered "a regulated air pollutant for permitting purposes" because there were "no regulations or standards prohibiting, limiting, or controlling the emissions of greenhouse gases."

With the foregoing background, it is clear that Congress did not make CO2 a pollutant subject to regulation when it enacted the provisions of Section 821 of Public Law 101-549. As a part of the 1990 Amendments to the Clean Air Act, Congress included a new title IV that established an acid rain control program. In the same legislation, Public Law 101-549, Congress also enacted Section 821, which, though not codified as a part of the Clean Air Act, contained requirements supplemental to Title IV whereby certain sources are to monitor and report their emissions of carbon dioxide. However, Sec. 821 does not require sources to limit or control their carbon dioxide emissions. When Congress enacted Sec. 821 of Public Law 101-549, it was fully aware of the U.S. EPA's interpretation that the phrase "subject to regulation" meant only pollutants that were subject to actual emission controls.

Technical Comment No. 34:

More details on the permit flaring provisions (e.g. reporting, root cause analysis, corrective actions, and what BP does when the INEOS flare is unavailable) should be provided.

Response:

The OCC project at BP Whiting includes a number of upgrades to the refinery which will improve overall reliability and are expected to result in a lower frequency of startup, shutdown, and malfunction events. Additionally, flare gas recovery systems will be installed as part of the new flare systems under the OCC project. These will serve to further reduce the emissions from SSM events. BP will continue to comply with all regulatory requirements regarding flaring events. When the INEOS flare is unavailable, BP has a procedure for venting propylene storage drums and tank cars to the refinery fuel gas system. (Also see Response to Technical Comment #1 for additional information related to flaring.)

The draft permit already includes limitations on the pilot and purge gases combusted at the GOHT and South flares (in Condition D.35.1(g)). The HU flare is not designed for purging gas combustion, therefore, there is no limitation on purge gas usage for the HU flare.

D.35.1(g) The Permittee shall comply with the following fuel usage limits:

Flare ID	Fuel Usage Limit (10^3 cubic feet per 12 consecutive month period)
GOHT-pilot	3,679.2
GOHT-purge	24,703.2
South flare-pilot	3,679.2
South flare-purge	28,908.0

Technical Comment No. 35:

a. (Councilman Mark Kalwinski, Hammond, IN) It is of concern that USEPA has initiated enforcement action against BP for making modifications to the plant, increasing

emissions while allegedly not following the permit process. If USEPA's position is substantiated, then continued monitoring should be implemented so real reduction of emissions are provided to the public - this way the public can make decisions based on accurate information.

b. BP has projected that it will increase its emissions of microscopic particulate matter by 21 percent annually after the project is complete. According to the America Lung Association, more than 2000 peer reviewed studies since 1996 have validated research that particle pollution can cause illness, hospitalization and premature death.

Members of the Calumet Project placed a metal collection plate in a residential area near the BP refinery for two weeks in September of 2007. Following prescribed quality control procedures, Coalition members wiped a square ten centimeter area on a clean sample collection paper supplied by a U.S. EPA approved laboratory. The sample wipe was chilled to keep the material from deteriorating, packaged, and shipped overnight to the EPA approved lab for testing. The results were forwarded to an internationally recognized expert, Dr. Mark Cherniak, for interpretation.

Dr. Cherniak identified five hazardous substances from the particle fallout from Whiting for major concern. He calculated the measured densities to present them in micrograms per square meter so they could be compared to EPA health standards. All of the five are substances that are polyaromatic hydrocarbons (PAHs) whose effects include increased risk of cancer that may develop over a long exposure even at low levels. Dr. Cherniak is convinced that this sample represents a health risk to the people who have to breathe it day in and day out.

The commenter cannot simply tolerate a 21% increase in dangerous particle pollution from the BP refinery tar sands expansion. This is an Environmental Injustice not only for the community of Whiting but surrounding communities as well. The commenter poses the following questions:

1. Will IDEM monitor the air at BP and the surrounding neighborhood on a daily basis with real time monitoring?

2. Will IDEM monitor the air at BP and the surrounding area around Lake Michigan for particulate matter that falls into the lake, Northwest Indiana's drinking water and a natural resource, for a 3 mile radius with real time monitoring?

c. Are there monitors in Lake County and will IDEM review the existing monitoring system to assure compliance?

d. (Carolyn Marsh) How many IDEM air monitors will check the air for pollutants at Whiting, East Chicago and Hammond under the air permit?

Response:

IDEM operates an extensive network of monitoring sites in Lake County, many near BP. The following list is for sites near BP. All sites are EPA approved and operated as specified by EPA rule requirements. Indiana has a robust, EPA-approved QA/QC program. A map of monitoring sites was provided at the BP Whiting public meeting and hearing.

<u>$PM_{2.5}$</u>: The standard monitoring cycle for $PM_{2.5}$ is every three days. IDEM operates sites at East Chicago - Franklin School, Hammond-Purdue, and Hammond - Robertsdale on this schedule. There is also a continuous monitor at Robertsdale. A speciated $PM_{2.5}$ monitor is operated at Hammond - Purdue.

PM_{10}: East Chicago - Franklin School, East Chicago - Water Filtration Plant, and Hammond - Robertsdale. These are 1 in 6 day samplers.

Ozone: Whiting High School and Hammond CAAP - continuous during May - October (Ozone season).

SO_2: Hammond CAAP - continuous.

Lead: East Chicago - Water Filtration and Hammond CAAP.

Toxics: East Chicago - Water Filtration, Whiting H.S., and Hammond CAAP

Technical Comment No. 37 (NRDC Group):

The draft Permit fails to require all practical and economically feasible control methods for virtually all new emission units and modifications of existing emission units. These include the following:

SCR should be used on all combustion sources with a firing rate of 50 MMBtu/hr or more, designed to remove 90% of the NOx;

SCR should be used on FCUs regenerator gases, designed to remove 90% of the NOx;

Oxidation catalysts should be used on all combustion sources with a firing rate of 50 MMBtu/hr or more, designed to remove at least 90% of the CO and 50% of the VOC;

Pall filters should be used on the FCU regenerator gases, designed to remove 99.99% of the PM;

A scrubber should be used on the FCU regenerator gases, designed to remove >95% of the SO2;

Fuel sulfur content should be limited to no more than 20 ppmv total sulfur, expressed as H2S on a 4-hour average, achievable using Sulfatreat and other sulfur removal technologies;

Cooling towers should be equipped with drift eliminators, designed with a 0.0005% drift rate;

A wet electrostatic precipitator should be used to control sulfuric acid mist emissions from the sulfur recovery units;

Leakless components should be used where available;

Tanks should be vented to a vapor recovery system designed to remove >99% of the hydrocarbon vapors.

Response:

IDEM has determined that none of the new or existing emission units at this facility are subject to BACT or LAER, based on the determination that the project is minor under 326 IAC 2-2 (PSD rules), 326 IAC 2-3 (Emission Offset rules) and 326 IAC 2-1.1-5 (Nonattainment NSR rules, NA NSR). The draft permit requires the Permittee to demonstrate compliance with the limitations established in the permit, including federal and state regulations that are applicable to the emission units. Therefore, IDEM does not have the authority to require additional controls beyond those necessary to meet the limits included and established in this permit.

Technical Comment No. 38:

a. (NRDC Group) IDEM failed to conduct BACT analysis for increased PM2.5 emissions from the project as required by the CAA. The permits impermissibly substitute regulation of PM10 for PM2.5.This surrogate approach not only violates the letter of the law, but fails to guarantee that increases in particulate matter from the project will be offset by qualitatively equal or less harmful reductions, in violation of state and federal "netting" regulations.

The permits must directly apply nonattainment NSR regulations to PM2.5. The proposed Whiting Refinery expansion will be located in an air quality control region designated nonattainment for ozone and fine particulate matter (PM2.5). 70 Fed. Reg. 944 (Jan. 5, 2005). As the result of a formal rulemaking by USEPA, this designation determines the applicable NSR program unless and until USEPA redesignates the area or the designation is overturned by a court of law. See 326 IAC 2-3-2(a) (nonattainment NSR); 326 IAC 2-2-2(b) (PSD); 326 IAC 2-3-2(a) (emissions offset regulations apply to a major modification constructed in an area designated "as of the date of submittal of a complete application," as nonattainment "for a pollutant for which the stationary source or modification is major"); 40 C.F.R. 81.300 (revision procedure for designations). Thus, the permits must comply with the nonattainment NSR rules for PM2.5.

As USEPA notes, fine particles are believed to pose the "largest health risks," due to their ability to lodge deeply in the lungs. PM2.5 is associated with aggravation of respiratory and cardiovascular disease, lung disease, asthma attacks, cardiovascular problems such as heart attack and arrhythmia, and even premature death. Children and the elderly are particularly susceptible to the negative impacts of PM2.5, the former because their immune and respiratory systems are still developing and the latter because their systems are weak and compromised. For these reasons, it is crucial that the Permits contain the appropriate and mandated direct limits on PM2.5.

However, nowhere did BP or IDEM actually apply the nonattainment NSR requirements to the proposed project's PM2.5 emissions. They instead treated PM2.5 as if it were PM10, then used the nonattainment NSR regulations for PM10 to address PM2.5: "OAQ is following the U.S. EPA's guidance to regulate PM10 emissions as a surrogate for PM2.5 emissions pursuant to the requirements of Emission Offset, 326 IAC 2-3." TSD at p. 3 of 32. This use of PM10 as a surrogate for PM2.5 violates federal and state law. BP must resubmit its permit application with a direct assessment of PM2.5, including application of nonattainment NSR requirements to the project's PM2.5 emissions, and IDEM must reissue the Permits with appropriate direct limits on PM2.5.

Use of PM10 as a surrogate for PM2.5 violates Indiana and Federal law. Using PM10 as if it were PM2.5 violates federal and state law. The Clean Air Act contains specific requirements regarding areas whose air quality violates the National Ambient Air Quality Standards, or NAAQS. USEPA since 1997 has distinguished PM2.5 from PM10, most importantly by setting different NAAQS for each. Both the federal and Indiana NSR program treat PM2.5 and PM10 separately in terms of attainment designations in relation to these separate standards. Thus, the proposed Whiting Refinery will be located in an area designated as "attainment" for PM10 and nonattainment for PM2.5.

USEPA has expressly recognized that fine particles, or those less than 2.5 micrometers in diameter, are "very different" from coarse particles (from 2.5 to 10 micrometers) in terms of sources, characteristics, and potential health effects. These differences mean that states will have to "evaluate different sources for controls, to consider controls of one or more precursors in addition to direct PM emissions, and to adopt different control

strategies" in order to implement the PM2.5 NAAQS compared to the PM10 NAAQS. Grounding these needs is the engineering reality that controls designed for capture of PM10 (consisting primarily of filterable particles) do not effectively capture PM2.5 (made up in large part of condensable particles).

Indiana law prohibits IDEM from issuing a permit unless the permit is protective of the public health and will not cause or contribute to a violation of the NAAQS. 326 IAC 2-1.1-5(a)(1) and (4). In addition, the Indiana nonattainment offset provisions apply to a source that emits a "significant emissions increase" and "significant net emissions increase" of a "regulated NSR pollutant." 326 IAC 2-3-2(c)(1). A "regulated NSR pollutant," in turn, includes "any pollutant for which a national ambient air quality standard has been promulgated." As stated above, USEPA has issued separate NAAQS for PM2.5 and PM10 based on the differences between them. BP and IDEM therefore must determine directly whether the project will result in a significant emissions increase and significant net emissions increase of PM2.5 to ensure protection of the public health and compliance with the NAAQS.

Under Indiana law, a significant emissions increase and significant net emissions increase in PM2.5 triggers nonattainment NSR. The agency must apply the regulation as written, which requires offsets where the source will result in a "significant emissions increase" and "significant net emissions increase." 326 IAC 2-3-2(c)(1) (emphasis added). The lack of a numeric significance level for PM2.5 in the Indiana regulations does not absolve IDEM from determining directly whether the project will result in a significant emissions increase and significant net emissions increase. Rather, these numeric significance levels only apply to the pollutants listed at 326 IAC 2-3-1(qq) ("significant" in reference to a net emissions increase "to emit any of the following pollutants".

If a numeric significance level were a prerequisite to determining whether a pollutant triggers offset requirements, the Indiana regulations would limit "significant" for all regulated NSR pollutants to the numeric list at 326 IAC 2-3-1(qq). The regulations instead state that this list only determines whether a significant emissions increase will occur for "a regulated NSR pollutant." 326 IAC 2-3-1(rr) (emphasis added). Thus, a gap exists in the numeric significance levels – *but not in the triggering provision itself*. The triggering provision instead continues to require that BP and IDEM determine whether the project will result in a "significant emissions increase" and "significant net emissions increase" of PM2.5 to ensure protection of the PM2.5 NAAQS, due to the differences between PM2.5 and PM10 described above. No such determination of significance has occurred for PM2.5 from the Whiting Refinery, and thus the permits cannot issue.

IDEM cannot rely on guidance that is in conflict with statutory and regulatory requirements, and is no longer technically justified. IDEM based its decision to pretend that the expansion project's PM2.5 emissions were PM10 on "U.S. EPA's guidance to regulated PM10 emissions as a surrogate for PM2.5 emissions pursuant to the requirements of Emission Offset, 326 IAC 2-3." TSD at 3 of 32. The TSD does not provide any additional explanation identifying this guidance or justification for the agency's reliance on it. Therefore, these comments will address reliance on USEPA guidance in terms of the "Seitz Memo"35 and "Page Memo"36 of which Commenters are aware. Reliance on these documents, or any similar guidance, is improper and invalidates BP's and IDEM's so-called analysis of PM2.5. Reliance is improper for three primary reasons, as follows.

First, IDEM cannot rely on USEPA guidance that does not have the force of law where, as here, that guidance is in conflict with statutory and regulatory requirements.37 As discussed above, federal and state law require BP and IDEM to analyze directly and

directly ensure compliance with the PM2.5 NAAQS. The Seitz Memo clearly states that it does not bind states, local governments and the public as a matter of law.

Second, USEPA's recommended use of PM10 as a surrogate for PM2.5 expired by its own terms when USEPA published the final PM2.5 implementation rule in September 2007. The 1997 Seitz Memo provided *interim* guidance for implementing the new PM2.5 NAAQS. This now nearly ten-year-old memo stated that sources could use the PM10 surrogacy approach to meet NSR requirements until certain difficulties were resolved, most notably with respect to monitoring, emissions estimation, and air quality modeling. The more recent, but still dated for the purposes of the BP project, Page Memo reaffirmed the surrogacy approach specifically for nonattainment NSR. The Page Memo noted that U.S. EPA recommended using PM10 as a surrogate for PM2.5 "until [U.S. EPA] promulgate[s] the PM2.5 implementation rule."

Not more than six months later, USEPA published a proposed PM2.5 implementation rule. The proposed rule made clear that the surrogacy approach would expire when the proposed rule was finalized:

Once this PM2.5 implementation rule is finalized, States will have the necessary tools to implement a major NSR program for PM2.5. States will no longer be permitted to implement a nonattainment major NSR program for PM10 as a surrogate for the PM2.5 nonattainment major NSR program.

Under the Title V regulations, major sources have an obligation to include in their Title V permit applications all emissions for which the source is major and all emissions of regulated air pollutants. The definition of regulated air pollutant in 40 C.F.R. 70.2 includes any pollutant for which a NAAQS has been promulgated, which would include both PM10 and PM2.5. To date, some permitted entities have been using PM10 emissions as a surrogate for PM2.5 emissions. *Upon promulgation of this rule, EPA will no longer accept the use of PM10 as a surrogate for PM2.5*.

BP and IDEM therefore had nearly two years notice that the surrogate approach was about to expire, well in advance of BP's submission of its applications. Most notably, the company and agency had notice prior to the application version serving as the basis for the present Permits, submitted in the fall of 2007 many months *after* promulgation of the final PM2.5 rule. The April 2007 final rule clearly affirms USEPA's rejection of the surrogacy approach: "the EPA will no longer accept the use of PM10 emissions information as a surrogate for PM2.5 emissions information given that both pollutants are regulated by a National Ambient Air Quality Standard and therefore are considered regulated air pollutants." Reliance on guidance that USEPA itself has abandoned is in direct conflict with the NSR requirements.

Third, technical difficulties in directly implementing the PM2.5 NAAQS that grounded the interim guidance back in 1997 have been resolved. USEPA itself noted in the preamble to the November 2005 Proposed PM2.5 Implementation Rule that these technical concerns have been resolved: "As discussed in this preamble, *those difficulties have been resolved in most respects, and where they have not been, the proposal contains appropriate provisions to account for it*." USEPA also has included the PM2.5 algorithms in the AERMOD air quality computer modeling program, the recommended model for short distance air quality assessment, thus formally resolving the Seitz' Memo's concerns about PM2.5 modeling capabilities. The Permits Cannot Rely on Reductions in Less Harmful PM10 in Order to "Net Out" of Nonattainment NSR for PM2.5.

Using PM10 as a surrogate for PM2.5 means that some increases in PM2.5 are likely to be offset by decreases in PM10. Such substitution of decreases in less harmful pollution

for more harmful increases violates the federal and state nonattainment NSR "netting" provisions. BP and IDEM must instead only offset PM10 increases with PM10 decreases and PM2.5 increases with PM2.5 decreases. Direct offset of PM10 and PM2.5 with in-kind reductions will meet the requirement that the refinery not offset more harmful emission increases with less harmful emission decreases. Otherwise, the netting calculations for particulate matter are in error.

In order to be creditable for netting purposes in a nonattainment area, a reduction in emissions at an existing unit must have "approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change." 326 IAC 2-3-1(dd)(3)(B)(v)(DD). This provision mirrors and must be at least as stringent as the parallel federal requirement, 40 C.F.R. § 51.166(b)(3)(vi)(c) (qualitative public health significance); see 40 C.F.R. 51.155(a)(7)(iv) (state implementation plan PSD provisions must be "more stringent than or at least as stringent in all respects" as the corresponding federal provision), whose purpose is to prevent proposed units from netting reductions in less harmful emissions against increases in more harmful emissions. 45 Fed Reg 52676 at Lexis p. 41 (1980).44 Thus, under both federal and Indiana law, a creditable reduction in emissions must be approximately as harmful, or less harmful, to public health and welfare than a proposed increase.

As described above, USEPA has found that the health effects associated with PM2.5 differ significantly from those linked to PM10, and that PM2.5 poses the largest health risks. A ton of PM10 therefore is not qualitatively the same as a ton of PM2.5 regarding impacts on public health. Using PM10 as a surrogate for PM2.5 in the nonattainment netting calculations means that neither BP nor IDEM can show that increases in very harmful PM2.5 will be sufficiently mitigated by creditable decreases with respect to health. A search of the permit documents shows that IDEM nowhere made the required determination that any of the claimed decreases met the qualitative public health significance criteria, let alone that decreases solely in PM10 from the project are of the same qualitative public health significance as the increases in PM10 and PM2.5 taken separately. The netting determinations for particulate matter in general and PM2.5 in particular therefore are unsupported, and the permits cannot issue.

b. (RHAMC) Why hasn't IDEM and/or BP separately calculated PM 2.5 emissions and impacts?

c. (Save the Dunes Council) PM2.5 is a special concern due to health concerns and the current air conditions.

Response:

The PM2.5 implementation rules were not effective at the time the Permittee submitted a complete permit application and are still not effective at this time. All references to particulate emissions in the permit and supporting documentation are stated as "PM" and include PM, PM10 and PM2.5 (filterable PM, filterable and condensable PM10). PM10 and PM2.5 emissions are assumed to be equal to total PM emissions for the Emission Offset minor limitations. For these analyses, IDEM has used the approach approved by the U.S. EPA to use PM10 as a surrogate for PM2.5.

On April 25, 2007, the U.S. EPA finalized its PM2.5 implementation rule. However, the U.S. EPA decided not to include the NSR program in the implementation rule and stated that, "because there was an interim surrogate NSR program in place" (which allowed states to use PM10 as a surrogate between the effective date of the PM2.5 NAAQS designation and until the U.S. EPA promulgates major NSR regulations for the implementation of PM2.5), EPA would finalize the NSR part of the rule in a separate rulemaking at a later date. On September 21, 2007, the U.S.

EPA proposed a separate rulemaking that proposed PM2.5 increments, Significant Impact Levels, and a Significant Monitoring Concentration to facilitate implementation of the PM2.5 PSD program. The preamble to that rule cites the interim surrogate policy for use of PM10 in lieu of PM2.5 as part of a transition program for PM2.5 implementation in NSR. The latter implementation rule has not been finalized.

Technical Comment No. 39:

a. (NRDC Group) BP and IDEM have provided insufficient information to determine whether the emissions calculations adequately account for higher levels of pollutants in tar sands crude oil. Crude oil extracted from Canadian tar sands, although still insufficiently studied in many respects, has been shown to contain higher levels of sulfur, nitrogen, harmful metals and other pollutants than conventional crude, and in some cases than other types of heavy crude. The application lacks any chemical composition data for the crudes that are currently processed and those that will be processed, preventing any meaningful of review of the impact of the change in crude slate on emissions. There is no way to tell from the information submitted by BP to IDEM whether BP took this fact into account in calculating its emissions. This is a critical omission, because factoring in this higher level of pollutants, to the extent that has not been done, could result in increased emissions that would trigger NSR requirements, including of hydrogen sulfide, reduced sulfur compounds, sulfuric acid mist, sulfur dioxide, lead, mercury, and beryllium, among others.

More generally, it is critical from a public health standpoint that the pollutant impact of refining tar sands crude be fully understood and appropriately controlled. As noted above, permits in Indiana must be “protective of public health,” independently from ensuring compliance with ambient air quality standards, PSD increments, and all other applicable air pollution control rules. 326 IAC 2-1.1-5. The permit thus must be based on a full accounting of these pollutants. Mercury is a potent neurotoxin. In addition, the U.S. EPA has determined that nickel refinery dust and nickel subsulfide are human carcinogens. According to one tar sands company, “The bitumen in the Canadian oil sands contains vanadium, nickel, and other metals in significantly larger quantities than occur in most other oils.” Nickel, vanadium and other metals occur in such high concentrations that companies are considering metals recovery from waste products.

Concerning mercury, the most recent study on mercury in crude in Canada includes data for one bitumen blend coming out of Alberta. Compared to conventional crude from Canada, the bitumen blend had a higher mercury content (range 5.0 – 10.7 parts per billion (ppb)). The synthetic crude (i.e., upgraded bitumen) oil samples from Alberta had mercury generally in the range of 0.1 – 2.4 ppb, with one sample having a much higher mercury concentration than even the bitumen (43.6 ppb). For the most part, conventional crude had concentrations below 2 ppb.

Specifically with respect to mercury, BP’s emissions factor for mercury from its FCUs is based on “engineering estimates,” which are not provided in the Alternative Emissions Factor Request form set forth above. While emissions from the FCUs are correlated with the mercury content of the expected crude feedstock (i.e., tar sands bitumen), it is impossible to confirm that, and assess its significance for the Project’s emissions, unless we can get the technical documentation for this engineering estimate from BP.

We note in addition that when USEPA promulgated its *National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries*, mercury from CCU catalyst regeneration vents was not included in the rule. After conducting a review of available data and technology, EPA concluded, “There are a number of emerging technologies (such as activated carbon injection) but none have been shown to be applicable to CCU

catalyst regeneration vents. Therefore, the MACT floor for Hg is determined to be no control for both new and existing units." In other words, the mercury that is burned off during catalyst regeneration is being emitted uncontrolled. In the absence of MACT controls for these sources, IDEM should, at minimum, require that mercury emissions from catalyst regeneration vents be monitored using DIAL or other appropriate technology.

b. (Susan MiHalo, Ogden Dunes, IN) Commenter has read that tar sands contain higher levels of harmful metals and other pollutants than conventional crude oil. The Vanadium and mercury levels are of particular concern, and IDEM should verify that the levels are indeed what they should be.

Response:

According to the application submitted by the Permittee and certified by the Responsible Official, there will be a net decrease in emissions of hydrogen sulfide, reduced sulfur compounds, sulfuric acid mist, sulfur dioxide, lead, mercury and beryllium. According to this application, and IDEM's evaluation of the information submitted therein, there is no increase in the air emissions of harmful metals, including nickel and vanadium. As with normal refinery processing, with the OCC project, the Ni and V and other metals contained in the Canadian crude will be retained in the "bottoms" during processing and are not emitted to the air.

With regard to Mercury, the Canadian crude to be processed as part of the OCC project has a similar mercury content to that of the crudes currently processed at the refinery. The following table provides a comparison of mercury contents of the principal crudes refined by Whiting pre- and post OCC. As indicated there, the weighted average mercury content of Whiting's overall crude slate is expected to decline after OCC.

Source	Type	Hg (ppb)	Pre-OCC	Post OCC
LLS	Sweet	5.0	39%	0%
MARS	Sour	7.3	43%	14%
Canadian Cold Lake	Dilbit	5.0	18%	60%
Canadian Cristina Lake	Synbit	1.0	0%	26%
Weighted Average Mercury (ppb)			4.8	4.3

There is very little information on mercury in FCCU emissions, and the data that are available are difficult to interpret due to the large number of values below detection. For example, a paper by Rene Bertrand and Jeffrey Siegel published in the October, 2002 edition of Environmental Progress (copy attached) reported the mercury concentrations in 23 samples of FCCU flue gas. Of these, 19 showed no detectable levels at a median detection limit of 7.51×10^{-6} lbs/1,000 lbs of coke burned. For the four samples that did show detectable levels, the median concentration was 2.27×10^{-5} lbs/1,000 lbs of coke burned while the mean was 5.24×10^{-5} lbs/1,000 lbs of coke burned. The difference between the median and mean for these four samples indicates that the mean was heavily influenced by a single high value that was probably an outlier.

Given these concerns and the fact that over 80% of the reported values showed no detectable mercury, BP considered an emission factor of 1.0×10^{-6} to be a reasonable engineering estimate. Two factors should be noted, however. First, the project would not result in a significant increase in mercury even if this emission factor were off by a factor of 700. Second, as discussed above, BP expects the overall mercury content of its crude slate to decline after OCC. As the commenter recognizes, this will mean that mercury emission factor from the FCCU will also decline as a result of OCC.

Technical Comment No. 40 (Barbara and Steven Fredman, Granger, Indiana)**:**

As citizens of Indiana who live downwind from Whiting, the Commenter is very concerned that BP will be using heavy crude oil from Canada that without proper equipment will be adding more pollutants into the air. St. Joseph County has a difficult time reaching air quality standards as they now stand without adding more contaminants into the air.

Response:

U.S. EPA established standards for several criteria pollutants. Among these are SO2, NOx, Ozone, and Fine Particulates (PM2.5). Emissions from most industrial sources include or affect these pollutants. According to the application submitted by the Permittee (certified by the Responsible Official), SO2 and NOx emission increases from this project have been offset by reductions and shutdowns elsewhere in the facility. Therefore, there will be no net NOx or SO2 increases. Based on this, the air quality in St. Joseph County will not be negatively impacted by the changes at BP. Since SO2 and NOx emissions do not increase, SO2 and NOx concentrations will not increase.

SO2 and NOx are "precursors", pollutants that react chemically downwind from the emissions source, to form PM2.5. Analyses performed on collected samples collected in St. Joseph County indicate that SO2 and NOx are major contributors to PM2.5 formation in that area. If these pollutants do not increase, neither should PM2.5 concentrations.

Similarly, ozone is formed by downwind chemical reactions of Volatile Organic Compounds (VOCs) and NOx. According to the application submitted by the Permittee (certified by the Responsible Official), VOCs associated with this project also are offset by reductions across the facility. Therefore, modifications to this facility will not increase measured ozone concentrations in St. Joseph County.

Technical Comment No. 41:

a. (NRDC Group) IDEM failed to require and include a schedule of Compliance for the violations identified in the NOV issued to BP on November 29, 2007, in connection with the Whiting refinery. Specifically, the NOV set forth detailed allegations concerning (i) a major modification to the facility's fluidized catalytic cracking unit designated as FCU 500 and to the UIU Flare at the facility, without compliance with NSR and NSPS requirements; (iii) violation of SO2 and reduced sulfur compound emission and monitoring limits at the sulfur recovery plant, and (iv) failure to conduct required performance testing and submit the results of the HCl emissions from Ultraformers 3 and 4 as required by the Refinery MACT II. The NOV further documented the health impacts of these violations, which include, among other things, respiratory illness, heart disease, lung damage, and premature death.

   In addition, deviation reports concerning flaring submitted to IDEM indicate repeated violations of current flare emissions limitations. Specifically, BP repeatedly exceeded the H2S 159 parts per million (ppm) 3-hour limit, meaning that too much H2S was burned in the flare. EPA limits H2S burned in the flare because when burned, H2S turns into harmful sulfur oxide emissions to the atmosphere.

   Under Title V of the CAA and associated regulations, IDEM was required to mandate submission of a schedule of compliance addressing these violations, and to include it in the Project Title V permit modification. CAA § 503(b)(1) requires that permit applicants "submit with the permit application a compliance plan describing how the source will comply with all applicable requirements under this chapter". 40 CFR 70.5(c)(8)(iii)(C),

promulgated pursuant to this provision, states that a permit application must include the following:

A schedule of compliance for sources that are not in compliance with all applicable requirements at the time of permit issuance. Such a schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the source will be in noncompliance at the time of permit issuance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject. In New York Public Interest Research Group v. Johnson, 427 F.3d 172 (2nd Cir. 2005) the court made clear that, where non-compliance has been demonstrated, agencies are obligated under the CAA to require a schedule of compliance in a Title V permit regardless of whether there has been an adjudicated determination of liability. The court found that an NOV – like the NOV issued to BP in November – was sufficient evidence of violations to require a schedule of compliance.

BP failed to submit the required schedule of compliance; and consequently, the Title V permit modification does not include one. IDEM must make a determination that BP's Title V permit application is incomplete, and require submission of a schedule of compliance to address all violations identified in the USEPA NOV, and the schedule of compliance must be incorporated into the permit.

b. (RHAMC) A fundamental purpose of the Title V permitting program is to ensure that regulated entities comply with requirements in the Clean Air Act. Under 40 C.F.R. § 70.1(b) and Clean Air Act § 504(a), each regulated major source must obtain a permit that "assures compliance by the source with all applicable requirements." A Title V permit applicant must disclose its compliance status and either certify compliance or enter into an enforceable schedule of compliance to remedy violations. 42 U.S.C. § 7661b(b); 40 C.F.R. § 70.5(c)(8-9).

Mindful of these requirements, on what basis does IDEM assert that a schedule of compliance or compliance plan is not required as part of issuing the Title 5 permit in lights of: a. the Finding and Notice of Violation issued by U.S. EPA Region 5 to BP Products North America, Inc., Whiting, Indiana on or about November 29, 2007, and, b. the Finding and Notice of Violation issued by U.S. EPA Region 5 to BP Products North America, Inc., Whiting, Indiana on or about January 25, 2007 (EPA-07-IN-03)?

The operating permits must include a compliance schedule remedying these violations. 40 CFR § 70.5(c)(8)(iii)(C). Pursuant to this section, if a facility is in violation of an applicable requirement at the time of permit issuance, the facility's permit must include a schedule leading to compliance with that requirement. The only exemption is if the reported violation has been corrected prior to permit issuance. Applicable requirements include, among others, the requirement to comply with state implementation plan ("SIP") requirements. *See* 40 C.F.R. § 70.2. If a facility is in violation of an applicable requirement at the time that it receives an operating permit, the facility's permit must include a compliance schedule. *See* 40 C.F.R. § 70.5(c)(8)(iii)(C). The compliance schedule must contain "an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the source will be in noncompliance at the time of permit issuance." *See* 40 C.F.R. § 70.5(c)(8)(iii)(C).

Response:

Please see response to "EPA Comment No. 6".

Technical Comment No. 42 (NRDC Group)**:**

The permit does not contain practically enforceable emission restrictions, production and operating conditions, monitoring, and recordkeeping to assure that emissions remain below the significance thresholds. The Permits do not limit all sources to ensure the emissions remain below significance thresholds, as it is required to do by law. The Permits also do not contain limits for all pollutants and sources as set out in the TSD. Finally, some of the limits are not enforceable as a practical matter.

A. Emissions Limits Are Missing

The Application and TSD claim the facility nets out of NSR review for H2S, reduced sulfur compounds, sulfuric acid mist, beryllium, lead, and mercury. However, the Permits do not contain any limitations on the emission of these substances nor require any testing to demonstrate that the claimed reductions and future potential emissions are achieved. Thus, the claim that the Project nets out of NSR review is a hollow promise, and inconsistent with applicable CAA requirements.

B. Testing Is Inadequate

The Permits require NOx CEMS on some combustion sources, but otherwise require only stack testing every five years for only one representative source from an arbitrary group of alleged similar sources. This is not adequate to assure that the emission reductions and future potential emissions assumed in the netting analysis are achieved in practice.

The claimed emission reductions can only be enforced through appropriate monitoring, testing and reporting of emissions. An appropriate hierarchy for specifying monitoring to determine compliance is: (1) continuous direct measurement where feasible; (2) initial and periodic direct measurement where continuous monitoring is not feasible; (3) use of indirect monitoring, e.g. surrogate monitoring, where direct monitoring is not feasible; and (4) equipment and work practice standards where direct and indirect monitoring are not feasible. NSR Manual, p I.3. The Permits do not comport with this guidance, and in some instances do not require any testing to demonstrate that the emission limits will be complied with when the source is operating.

First, testing should be required for every fired source, not just one out of the proffered groupings as fired sources, even when superficially identical, can differ from unit to unit as refinery fired sources are not off-the-shelf technology. Hundreds of stack tests of boilers and refinery heaters from across the country demonstrate that emissions are highly variable and depend upon the degree of air preheat, age of the unit, maintenance practices, type of burners, etc. The Permits must be modified to require testing of all emission units, not just one from a grouping.

Second, the infrequent testing does not provide sufficient data to determine if the assumptions used in the netting analysis are realized. Further, it is not adequate to allow IDEM, U.S. EPA or the public to ensure compliance with the Permit limits. It is feasible to directly and continuously monitor CO, VOC, and NOx emissions from all heaters, boilers, and other fired sources. The draft Permits only require continuous emission monitors for NOx from some fired sources. It is also feasible to conduct more frequent stack tests. Annual or more frequent testing is feasible, is commonly required for similar facilities, and should be required here. Finally, annual fugitive emission inventories for PM/PM10 and VOCs are required elsewhere and should be required here. Thus, the draft Permits should be modified to require more frequent direct emission testing.

Response:

A. The netting analysis submitted by the Permittee (and certified by the Responsible Official) shows a net decrease in emissions for H2S, reduced sulfur compounds, sulfuric acid

mist, Pb, Be, and mercury. The decreases from the shutdown of existing units are made enforceable in the permit by requiring the unit to be shutdown prior to the completion of the OCC project. The increases from new emission units are based on the potential to emit of these pollutants as estimated by the Permittee. The resulting creditable decreases exceed the potential emissions increase for these pollutants, so it is not necessary to establish limits.

With regard to the adequacy of testing requirements in the draft permit, IDEM has reviewed the testing requirements included in the draft permit, and in response to that evaluation, has revised the requirements to include a significant increase in the number of units to be tested and requirements to test units on a more frequent basis. The revised schedule includes representative testing of less significant heater units on a more frequent basis than other recently-permitted refineries, aggressively addresses failed tests and retesting. Emissions from these heater units are minimal in regards to the overall project and facility. These units have been conservatively categorized by size, and emission characteristics, and all units in each category must be tested. The fuel gas combustion sources are similar in construction and operation, and thus are expected to have consistent combustion and emission characteristics, since they burn refinery fuel gas that comes from a common origin. Variations in emissions that may occur at these sources due to differences in heater size and age were also considered. In order to obtain a representative selection of sources to test, the emission sources were divided into categories. These categories were defined by type of unit, age of the unit, size (e.g. firing rate in MMBtu/hour), and emission factor. The result was multiple groups, which range in size from 1 to 9 units, containing units that for a given pollutant, are expected to have the same emission rate in lbs/MMBtu and that utilize the same fuel.

In addition to the aforementioned testing requirements included in this permit, there are a significant number of units which have CEMs that monitor both NOx and CO emissions. For SO2, the source monitors the refinery fuel gas continuously for total reduced sulfur and H2S to ensure compliance with the 80 ppm limit on sulfur content, ensuring compliance with SO2 limitations across the facility for units combusting refinery fuel gas.

We believe, with these revisions, the compliance monitoring and emission testing included in this permit are sufficient for assuring compliance with the limitations in the permit on a continuous basis.

In regards to annual fugitive emission inventories, the permit already includes a requirement, pursuant to D.0, to account for fugitive emissions to demonstrate compliance with the PSD and EO minor limitations in the permit.

The following changes the testing requirements have been made to D.0.3:

D.0.3 Testing Requirements

(a) Tests shall be conducted on new, modified and affected emission units that are included in the CXHO project, utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C - Performance Testing. PM-10 includes both filterable and condensible PM-10. **For heaters with a maximum heat input greater than or equal to 100 MMBTU/hr and FCU 500 and FCU 600, these tests shall be repeated at least once every three years from the date of the previous valid compliance demonstration. For heaters with a maximum heat input greater than or equal to 50 MMBTU/hr but less than 100 MMBTU/hr and the SRU COT 1 and COT2, these tests shall be repeated at least once every four years from the date of the previous valid compliance demonstration**. **For heaters with a maximum heat input less than 50 MMBTU/hr,** ~~T~~these tests shall be repeated at least once every five years from the date of the previous valid compliance

demonstration. **Subsequent compliance demonstrations shall include testing of a different emission unit than the emission unit tested for the previous compliance demonstration until all units within a group have been tested.**

(b) Tests shall be conducted in accordance with the following deadlines:

(1) For a group that includes new or modified emission units (CO-1**a, CO-1d, CO-3b**, PM/VOC-1, PM/VOC-2, PM/VOC-3, PM/VOC-4**a, PM/VOC-4b**, VOC-6, PM/VOC-7, NOx-1, **NOx-2**, NOx-4, NOx-8, NOx-12), tests shall be conducted on one of the representative heaters in that group: within 180 days of startup of a new emission unit, or modification of an existing emission unit within that group.

(2) For a group that includes only existing affected units (**CO-1b, CO-1c**, CO-2, **CO-3a**, CO-4, PM/VOC-5**a, PM/VOC-5b, PM/VOC-5c, PM/VOC-5d**, PM/VOC-8, PM/VOC-9, ~~NOx-2~~, NOx-3, NOx-5, NOx-6, NOx-7, NOx-9, NOx-10, NOx-11), tests shall be conducted on one of the representative heaters in that group within 180 days of the start-up of the New Coker (#2 Coker) **and the re-start of the No. 12 Pipestill (after the completion of the permitted modifications), whichever occurs later.**

(c) The emissions units to be tested in order to demonstrate compliance with Prevention of Significant Deterioration (326 IAC 2-2), Emission Offset (326 IAC 2-3) and Nonattainment NSR (326 IAC 2-1.1-5) minor limits shall be grouped as follows:

~~Table D.0.2 Test Groups~~		
~~Pollutant~~	~~Test Group ID~~	~~Emission Units in Group~~
~~CO~~	~~CO-1~~	~~11A PS heaters H-1X, H-2, H-3~~ ~~11C PS heaters H-200, H-300~~ ~~4 UF heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, F-8B~~ ~~ARU heaters F-200A, F-200B~~ ~~BOU heater F-401~~ ~~CFHU heaters F-801A, F-801B~~ ~~CRU heaters F-101, F-102~~ ~~ISOM heater H-1~~
	~~CO-2~~	~~DDU heaters WB-301, WB-302~~
	~~CO-3~~	~~HU heater B-501~~
	~~CO-4~~	~~CFHU heater F-801C~~
	~~No stack test required (equipped with CO CEMS)~~	~~New Coker (#2 Coker) heaters H-201, H-202, H-203~~ ~~12 PS heaters H-101A, H-101B, H-102~~ ~~DHT heater B-601A~~ ~~New HU heaters HU-1, HU-2~~ ~~SRU COT1, COT2~~ ~~FCU 500, FCU 600~~ ~~3 SPS boilers/duct burners 1, 2, 3, 4, 6~~ ~~New Boiler 1, New Boiler 2~~
~~VOC and PM/PM-10~~	~~PM/VOC-1~~	~~New Coker (#2 Coker) heaters H-201, H-202, H-203~~
	~~PM/VOC-2~~	~~New HU heaters HU-1, HU-2~~
	~~PM/VOC-3~~	~~SRU COT1, COT2~~
~~* VOC test group only~~		
	~~PM/VOC-4~~	~~11C PS heater H-200~~

~~Table D.0.2 Test Groups~~		
~~Pollutant~~	~~Test Group ID~~	~~Emission Units in Group~~
		~~12 PS heaters H-101A, H-101B, H-102~~ ~~BOU heater F-401~~ ~~GOHT heaters F-901A, F-901B~~ ~~DHT heater B-601A~~ ~~ISOM heater H-1~~ ~~HU heater B-501~~
	~~PM/VOC-5~~	~~11A PS heaters H-1X, H-2, H-3~~ ~~11C PS heater H-300~~ ~~4UF heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A,F-8B~~ ~~ARU heaters F-200A, F-200B~~ ~~CFHU heaters F-801A, F-801B, F-801C~~ ~~CRU heaters F-101, F-102~~ ~~DDU heaters WB-301, WB-302~~
	~~VOC-6*~~	~~3 SPS boilers 1, 2, 3, 4, 6~~
	~~PM/VOC-7~~	~~New Boiler 1, New Boiler 2~~
	~~PM/VOC-8~~	~~FCU 500~~
	~~PM/VOC-9~~	~~FCU 600~~
~~NOx~~	~~NOx-1~~	~~CFHU heater F-801C~~ ~~GOHT heaters F-901A, F-901B~~ ~~DDU heater WB-301~~
	~~NOx-2~~	~~11C PS heater H-200~~
	~~NOx-3~~	~~CRU heaters F-101, F-102~~
	~~NOx-4~~	~~4UF heaters F-3, F-4, F-8A, F-8B~~ ~~ARU heaters F-200A, F-200B~~ ~~ISOM heater H-1~~
	~~NOx-5~~	~~4UF heater F-2~~
	~~NOx-6~~	~~11A PS heater H-1X~~
	~~NOx-7~~	~~11C PS heater H-300~~
	~~NOx-8~~	~~11A PS heater H-2, H-3~~ ~~4UF heaters F-1, F-5, F-6, F-7~~ ~~BOU heater F-401~~
	~~NOx-9~~	~~CFHU heaters F-801A, F-801B~~
	~~NOx-10~~	~~HU heater B-501~~
	~~NOx-11~~	~~DDU heater WB-302~~
	~~NOx-12~~	~~SRU COT1, COT2~~
	~~No stack test needed (NOx CEMS)~~	~~3 SPS boilers 1, 2, 3, 4, 6, New Boiler 1, New Boiler 2~~ ~~New Coker (#2 Coker) heaters H-201, H-202, H-203~~ ~~12 PS heaters H-101A, H-101B, H-102~~ ~~New HU heaters HU-1, HU-2, and FCU 500, FCU 600~~ ~~DHT heater B-601A~~

Table D.0.2 Test Groups			
Pollutant	**Test Group ID**	**Emission Units in Group**	**Testing Frequency**
	CO-1a	**11A PS heater H-1X, 11C PS heater H-200 4 UF heaters F-2, F-3, F-8A, F-8B ARU heaters F-200A, F-200B ISOM heater H-1**	**Every 3 years**
	CO-1b	**11C PS heater H-300 4 UF heater F-4**	**Every 4 years**
	CO-1c	**11A PS heaters H-2, H-3 4 UF heaters F-1, F-5, F-7**	**Every 5 years**
	CO-1d	**4 UF heater F-6 BOU heater F-401 CFHU heaters F-801A, F-801B CRU heaters F-101, F-102**	**Every 5 years**
	CO-2	**DDU heaters WB-301, WB-302**	**Every 4 years**
	CO-3a	**HU heater B-501**	**Every 3 years**
	CO-3b	**GOHT heaters F-901A, F-901B**	**Every 5 years**
	CO-4	**CFHU heater F-801C**	**Every 5 years**
	No stack test required (equipped with CO CEMS)	**New Coker (#2 Coker) heaters H-201, H-202, H-203 12 PS heaters H-101A, H-101B, H-102 DHT heater B-601A New HU heaters HU-1, HU-2 SRU COT1, COT2 FCU 500, FCU 600 3 SPS boilers/duct burners 1, 2, 3, 4, 6 New Boiler 1, New Boiler 2**	**Not applicable**
VOC and PM/PM-10 * VOC test	**PM/VOC-1**	**New Coker (#2 Coker) heaters H-201, H-202, H-203**	**Every 3 years**
	PM/VOC-2	**New HU heaters HU-1, HU-2**	**Every 3 years**

Table D.0.2 Test Groups			
group only	PM/VOC-3	SRU COT1, COT2	Every 4 years
	PM/VOC-4a	11C PS heater H-200 12 PS heaters H-101A, H-101B, H-102 ISOM heater H-1 HU heater B-501	Every 3 years
	PM/VOC-4b	BOU heater F-401 GOHT heaters F-901A, F-901B DHT heater B-601A	Every 5 years
	PM/VOC-5a	11A PS heater H-1X 4UF heaters F-2, F-3, F-8A,F-8B ARU heaters F-200A, F-200B	Every 3 years
	PM/VOC-5b	11C PS heater H-300 4UF heater F-4 DDU heaters WB-301, WB-302	Every 4 years
	PM/VOC-5c	11A PS heaters H-2, H-3 4UF heaters F-1F-5, F-7	Every 5 years
	PM/VOC-5d	4UF heater F-6 CFHU heaters F-801A, F-801B, F-801C CRU heaters F-101, F-102	Every 5 years
	VOC-6*	3 SPS boilers 1, 2, 3, 4, 6	Every 3 years
	PM/VOC-7	New Boiler 1, New Boiler 2	Every 3 years
	PM/VOC-8	FCU 500	Every 3 years
	PM/VOC-9	FCU 600	Every 3 years
NOx	NOx-1	CFHU heater F-801C GOHT heaters F-901A, F-901B DDU heater WB-301	Every 4 years
	NOx-2	11C PS heater H-200	Every 3 years
	NOx-3	CRU heaters F-101, F-102	Every 5 years
	NOx-4	4UF heaters F-3, F-4, F-8A, F-8B ARU heaters F-200A, F-200B ISOM H-1	Every 3 years
11C PS heater H-300	NOx-5	4UF heater F-2	Every 3 years
	NOx-6	11A PS heater H-1X	Every 3 years
	NOx-7	11C PS Heater H-300	Every 4 years

Table D.0.2 Test Groups			
	NOx-8	**11A PS heater H-2, H-3 4UF heaters F-1, F-5, F-6, F-7 BOU heater F-401**	**Every 5 years**
	NOx-9	**CFHU heaters F-801A, F-801B**	**Every 5 years**
	NOx-10	**HU heater B-501**	**Every 3 years**
	NOx-11	**DDU heater WB-302**	**Every 4 years**
	NOx-12	**SRU COT1, COT2**	**Every 4 years**
	No stack test needed (NOx CEMS)	**3 SPS boilers 1, 2, 3, 4, 6, New Boiler 1, New Boiler 2 New Coker (#2 Coker) heaters H-201, H-202, H-203 12 PS heaters H-101A, H-101B, H-102 New HU heaters HU-1, HU-2, FCU 500, FCU 600 DHT heater B-601A**	**Not applicable**

(d) Within 180 days of the startup of New Coker (#2 Coker) **and the re-start of the No. 12 Pipestill (after the completion of the permitted modifications), whichever occurs later**, in order to demonstrate compliance with the PM-10 emission factor limit from the SCR stacks at No. 3 Stanolind Power Station (3 SPS), testing shall be conducted on one (1) of the five (5) stacks for 3 SPS boiler/SCR stacks, utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C - Performance Testing. PM-10 includes filterable and condensible PM-10. This test shall be repeated at least once every three years from the date of the previous valid compliance demonstration.

(d) In the event that a unit tested within a group exceeds an allowable emission limit established in the permit, the emission rate from that test shall be utilized to determine compliance with applicable emission limits at the other units within that group until such time as the Permittee conducts testing which demonstrates compliance with the applicable emission limits.

(e) Compliance with the emissions limits for each emission unit or test group shall be determined as follows:

$$T = \left(\sum_{i=1}^{n} T_i\right) / n$$

Where:
T = average of IDEM approved stack test results for emission unit or all units within that same group over a 12 month period
Ti = average of multiple runs during Test #i
n = number of IDEM approved stack tests during 12 month period

Technical Comment No. 43 (Carolyn Marsh)

Is the hazardous waste landfill on BP's property at the wastewater treatment plant next to Lake Michigan still active as a landfill? If so, what is the amount of hazardous waste sludge from the refining of Canadian tar sands oil discharged into it? Will the handling, loading and transportation of non-hazardous waste sludge to the Newton County landfill, discharge regulated and/or non-regulated pollutants into the air? If so, what are the pollutants? Will the handling, loading and transportation of hazardous waste sludge to the Sarnia Ontario Canada landfill, discharge regulated and/or non-regulated pollutants into the air? If so, what are the pollutants?

Response:

According to the application submitted by the Permittee and certified by the Responsible Official, all fugitive emissions increases from the OCC project have been included in the netting analysis. This would include fugitive emissions from all truck traffic and material handling at the source.

With regard to the onsite disposal of waste materials, BP does not operate an active hazardous waste landfill next to Lake Michigan. BP's fluidized bed incinerator which previously processed hazardous waste has been shutdown. BP has no plans to place any hazardous wastes generated at the refinery at the site. Some solid waste will continue to be generated at the refinery, although the OCC project has been designed to minimize the amount of waste generated. The refinery disposes of waste materials at various landfills, which may include Newton County and Sarnia landfill, in accordance with all state & federal regulations.

Technical Comment No. 44: (Mark Kalwinski, Councilman, City of Hammond):

Given opinions regarding IDEM not considering flare emissions, a 30-40% increase in CO2 emissions (4 billion pounds per year) and a 114 ton increase in PM emissions, IDEM should evaluate the permit and modify as necessary.

Response:

Please see the responses to "Technical Comment No. 1" for the flaring issue and "Technical Comment No. 18" for PM emissions.

Technical Comment No. 45 (Jim Sweeney, Schererville, IN):

Commenter asked whether BP using the best and latest technology for the controls in this permit?

Response:

According to the application submitted by the Permittee (certified by the Responsible Official), the OCC project is minor under PSD (Prevention of Significant Deterioration), EO (Emission Offset) and Nonattainment NSR rules, which means that the emissions units included in this project are not subject to Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). BP is however adding additional controls and installing lower emitting units as part of this project and will be required to operate these controls and achieve very stringent limitations as part of this permit to ensure that the project is minor.

Technical Comment No. 46:

(Randall Maull) As an employee for a local chemical worker's union, one of the Commenter's duties was to calibrate the monitoring device for SO2 standards. The standard was 300 parts per million. The standard here is 600 parts per million of SO2.

Response:

IDEM believes that the emission limitations and standards in the permit are as required by state and federal regulations.

Public Comments - General

General Comment No. 1:

Many commenters extended their support to this project for the reasons summarized below. These Commenters urged IDEM to issue the construction and operating permits for the CXHO project.

a. Fuel Cost and Availability
Many commenters expressed that not issuing the permit would adversely impact the supply of gasoline and diesel fuel available for consumers. They stated that the use of more Canadian crude oil will help minimize dependence on foreign oil supplies and reduce the chance of the disruption of crude oil deliveries. Some commenters stated that other domestic crude oil sources are in decline, while Canada has substantial crude oil. They stated that the project will result in increased refinery capacity and increased fuel supplies, which should stabilize the market and reduce future fuel costs.

b. Economic Impact
Many commenters expressed that the BP's proposed project will result in a positive economic impact to the area. They expressed that the many needed construction jobs and permanent jobs will be created by the project and the resulting revenue will create economic growth throughout the area. Some commenters stated that BP's investment will keep it at its current location and reduce the chance that it will relocate to some other area or country.

c. Better Air Quality
Commenters stated that the proposed air permit meets or exceeds regulatory standards and protects human health and the environment, significantly reducing regulated air emissions to below previous levels.

d. Other Causes of Poor Air Quality and Urban Sprawl
Lake County's air pollution is affected by air pollution from rural areas and Illinois. Rural areas burn leaves and trash. Stress and pollutants inside the home also cause poor air quality and illness. Urban sprawl, with the resulting long distance commuter traffic also increases pollution. Why is there no fight against urban sprawl?

e. BP is a good corporate citizen
Commenters stated that BP makes positive contributions to area causes that need BP's assistance.

f. Certainty in Environmental Permitting
Commenters noted that it is important to the economic development that environmental permit applicants be able to rely on the environmental permit application and issuance process as defined by federal and state law when considering the state of Indiana for such projects.

Decisions should be based on fact and not misinformation and fear mongering from radical environmentalist and some of the media.

Response:

IDEM acknowledges the opinion expressed by all Commenters who support this project. As stated in IDEM's Technical Support Document, the permit will result in a decrease in regulated emissions from the previous baseline level, resulting in better air quality. OAQ recognizes that concerns outside of air quality are important to those who expressed them; however, they do not have a direct impact on how IDEM reviews and makes decisions on air permit applications. IDEM, OAQ's air permit review, by law, cannot address issues for which it does not have direct regulatory authority.

General Comment No. 2:

Several Commenters expressed their opposition to the draft permits for the proposed modernization at the BP Whiting facility. Many of these Commenters also urged IDEM to grant additional time for citizens to review the permit (this issue has been addressed in response to "General Comment No. 2". Comments which included technical details have been included in the section titled "Technical Comments". Comments opposing the permit that include specific issues have been addressed in other responses in this "General Comments" section. The reasons for opposition to the permit and/or request for additional time for review are summarized below.

a. Public Health
Many commenters stated that the Indiana Department of Environmental Management should make public health the highest concern when permitting this project. Pollution emissions from the project will cause health problems for local residents. The project will significantly increase sulfur dioxide, particulate matter, soot and lead. Lead causes brain damage in children, sulfur dioxide and particulate matter cause an increase in lung disease, and air pollutants cause cancer. This area has a higher than national average cancer rate. IDEM should decrease emissions. IDEM should protect public health, not BP or jobs. BP will not go out of business if forced to stop all pollution in the air, soil and water of our home environment. Citizens deserve a healthy and safe community. Indiana's water is polluted with mercury and the air is polluted with pesticides and herbicides. This area has high concentrations of asthma and other pollution related illnesses. A hospital that serves ill people should not support a corporate initiative that creates pollution and makes people ill.

b. Michigan and Canadian Air Quality
Southwest winds in the summer season presently contribute to smog days in the area of Sarnia, ON, and Port Huron, MI. Shell Canada is in the process of investigating the feasibility of building a large refinery about 20 miles south of Sarnia. The probability that these two projects would combine to add pollutants is a concern. The area is located within and surrounded by Canada's Chemical Valley.

c. Public Involvement and Extension of Time
Commenters stated that IDEM has abrogated its duty to serve the public trust by failing to allow for meaningful public involvement in the permitting process. IDEM should have extended the public commenting period to allow for meaningful public participation and review of these extremely complex permits with over 6,000 pages to read. IDEM should allow a BP emissions offset credit to expire in June 2008 to allow more time for public review. IDEM should take more time with a project that has been called "[T]he most destructive project on earth" by the Environmental Defense Fund.

(Natural Resources Defense Counsel Comment) Given time, many more significant problems could be identified with these permits. Unfortunately, despite multiple requests for an extension of time for meaningful review of the permits, additional time was not granted. The permits - collectively thousands of pages long, are spectacularly complex, even by ordinary air permitting standards. Moreover, although a request (from the Illinois Attorney General, with whom Commenters are collaborating) for the documents in IDEM's files associated with the project permits was submitted in September 2007, IDEM did not actually begin responding to this request until February 2008. On February 8, IDEM produced 6,410 pages of permit documents. On February 22, February 27, March 12 and March 19, IDEM produced thousands of pages of additional document. IDEM has acknowledged that not even all of the relevant documents have been made available. Simply reviewing all of the documents in the initial February 8 shipment would require more than 500 hours. Experienced engineers consulted by the Commenter have described the netting calculations as the most complex they have ever seen.

(Legal Environmental Aid Foundation Comment) It is incomprehensible that IDEM will not allow the minimum to review more than 6,000 pages of highly complex technical data simply because this facility that IDEM is regulating wants to take advantage of an emission offset credit to avoid the more stringent requirements under PSD and new source review, offset credits that will expire on June 1st.

It is difficult to get documents from IDEM. I've been to IDEM many times and never received the documents I was looking for. The permitting process is flawed, and there is a lack of transparency. The draft permits and permit records are complex and the public notice and comment period is short. IDEM should let BP's emission reduction credits expire by waiting until after June 2008 to issue the permits.

d. Environmental Disaster

Commenters stated that BP is about to embark on one of the largest environmental disasters of our time-refining tar sands from Canada. The current technology is insufficient to provide for an environmentally acceptable approach to refining Canadian sand/shale crude oil.

e. Global Warming

The BP project will significantly increase the emissions of carbon dioxide from the plant, an additional 1.5 to two million tons per year. Carbon dioxide is causing global warming worldwide. Not only will this project directly impact the citizens of Indiana, and the residents of this region, but people, animals, and the ecosystem of North America. BP should sequester the carbon dioxide that it will produce. Carbon dioxide emissions should be lowered, not increased. BP estimates that carbon dioxide emissions will be increased by 30 to 40 percent, to as mush as 4 billion pounds. The federal Clean Air Act requires that carbon dioxide emissions be evaluated and controlled as an air pollutant, pursuant to New Source Review and the United States Supreme Court's recent decision in Massachusetts v. EPA, 127 S. Ct. 1438 (2007). BP must limit its greenhouse gas emissions within legal parameters. The Midwest will be negatively impacted by global warming with increased drought, increased highly acidic rainfall, decreased river and lake levels, longer heat waves, more extreme single day temperatures, increased health problems and premature death. BP needs to follow Conoco-Phillips example and offset its greenhouse gas emissions on a two-to-one carbon basis.

f. Alternative Sources of Energy

BP should instead invest in clean energy and solar energy programs. Solar components are built in Indiana and should be used here.

g. Tar Sand Mining and Related Refining

Shale and tar sand oil extraction causes horrendous Canadian environmental damage. Tar sand mining uses up local water to create a water and oil slurry. Tar sand mining is not cost effective. Tar sands oils should be thought of as a temporary fuel source and not a long-term solution. Tar sands mining will devastate an area in Alberta the size of the state of Virginia and uses more energy to process than conventional fuel.

h. BP's Environmental Record
In the annual report for British Petroleum, in 2006, BP was identified as a potential responsible party to 800 superfund sites. BP is not cleaning up the sites, they are creating more.

i. Lake County Ambient Air Monitors
The current air monitors in Lake County should be reviewed to ensure compliance.

j. Schedule of Compliance
The permits need to contain a schedule of compliance to address the violations that U.S. EPA found in its Notice of Violation sent to BP in November 2007.

k. BP is a Foreign Corporation
BP is a foreign corporation; most of its profits will not go to America or Americans.

Response:

a. Public Health
IDEM would not issue these permits if the permit terms were not protective of human health and the environment. BP's projected air emission increases for the project are being offset by recent actual emission reductions and projected reductions. These reductions include voluntary reductions done in the past five years and future emission reductions from existing equipment. The draft permits make these reductions legally binding. The net effect of all the BP air emission increases and decreases is a net reduction in BP's permitted air emissions. The draft permits require BP to reduce emissions by setting lower fuel usage limits for existing units and to further reduce emissions by adding new control equipment to existing equipment. The draft permits further require BP to reduce emissions by permanently shutting down older process heaters, the Fluidized Bed Incinerator and the #3 Ultraformer Unit.

The net emission reductions made enforceable by the permit will result in significant air emission decreases. Total particulate matter will decrease by 281 tons per year (TPY) and coarse particulate matter (PM10) will decrease by 41 TPY. Sulfur dioxide emissions will decrease by 200 TPY, total reduced sulfur emissions will decrease by 76 TPY and hydrogen sulfide emissions will decrease by 15 TPY. Carbon monoxide emissions will decrease by 23 TPY. Nitrogen oxides will decrease by 0.6 TPY. Volatile organic compound emissions will decrease by 14 TPY. Beryllium emissions will decrease by 0.005 TPY. Mercury emissions will decrease by 0.001 TPY. Lead emissions will decrease by 0.02 TPY.

IDEM has prepared the permits with all the applicable regulatory requirements to protect human health and the environment. IDEM's role as the environmental regulator is to make sure that BP is complying with all air pollution control laws. IDEM has no authority to require BP to reduce all of its emissions to zero.

b. Michigan and Canadian Air Quality
Ozone and ozone precursor emissions can travel great distances and impact areas far removed from the emission point. Emissions from the BP refinery could possibly travel over 300 miles and impact eastern Michigan and Canada. However, there is no evidence or indication that BP emissions are causing any significant impact on the air quality in those areas. IDEM also has no authority in these BP permit actions to consider the effect of a possible future Canadian refinery project.

c. Public Involvement and Extension of Time

OAQ notified the public that the two draft BP permits were available for public comment by mailing a notice to interested parties. IDEM also published the notice in The Post Tribune newspaper in Merrillville, in Lake County, and The Times newspaper in Munster in Lake County on February 11, 2008. The draft permit documents were made available for review at the Whiting Public Library, 1735 Oliver Street, Whiting, IN 46394, at IDEM's Northwest Regional Office, 8315 Virginia Avenue, Suite, Merrillville, IN 46410, at IDEM's main office in Indianapolis and at http://www.in.gov/idem/ on the internet. In addition, on February 11, 2008, IDEM issued a notice that it would conduct a public hearing and public meeting regarding the draft permits on March 14, 2008, at the Hammond Civic Center. This Public Notice that was mailed to interested parties. The notice was published in the Post Tribune newspaper in Merrillville and The Times newspaper in Munster. IDEM posted the notice on IDEM's website. After receiving requests to extend the comment period, IDEM made the decision to extend the public comment period to March 21, 2008, in order to give the public more time to comment. Because the last day of the public comment period fell on a day when IDEM offices were to be closed for business due to a state holiday, IDEM notified the public on its website that all comments must be postmarked or delivered in person by March 24, 2008, which was the next business day that IDEM was open.

IDEM considers all written comments, whether they are submitted in hardcopy or electronically. Under Indiana's air permit rules, specifically 326 Indiana Administrative Code 2-7-17, OAQ gives the public at least 30 days to submit written comments. OAQ set the pubic comment period deadline at March 24, 2008, which set the public notice period at 42 days.

IDEM believes that the length of the comment period was sufficient and appropriate. IDEM received a substantial number of comments within the public comment period, including numerous comments sent by e-mail and oral comments submitted during the public hearing. The technical comments IDEM received were very detailed and thorough showing extensive review of the draft permit documents.

IDEM would not have accepted and initiated processing of the permit application as received on November 1, 2007 if IDEM had determined that the permit could not be processed in a timely and correct manner. IDEM is obligated to issue permits within 120 days (plus 45 days for public meeting and hearing) of receipt of a complete application unless there are delays that meet requirements under title 326 of the Indiana Administrative Code.

IDEM has endeavored to respond to all information requests as promptly and efficiently as possible. In response to these numerous requests, IDEM has produced volumes of records, including the permit applications, supplemental information, letters and electronic mail regarding the project.

IDEM has no authority to delay the issuance of the permits simply to allow for BP's emission reduction credits to expire. IDEM wants to encourage BP and all regulated sources in Indiana to make voluntary pollution reductions beyond what IDEM can require by law. Not allowing BP to use these reductions would discourage sources from making such voluntary reductions.

d. Environmental Disaster

IDEM has prepared the permits with all the applicable regulatory requirements to protect human health and the environment. IDEM has no authority to consider whether better tar crude oil refining technology may be available in the future.

e. Global Warming

Carbon dioxide (CO_2) is not currently "subject to regulation" under the federal Clean Air Act (CAA). The U.S. Supreme Court's decision in Massachusetts v. Environmental Protection Agency, held that CO_2 was a "pollutant" and that the U.S. EPA must decide whether, or how, it should be regulated. The Court did not conclude that CO_2 is a pollutant "subject to regulation." In determining which pollutants are "subject to regulation" under the CAA, IDEM has followed the U.S. EPA interpretation that the phrase "subject to regulation" means pollutants that are subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant.

The U.S. EPA has consistently determined that a pollutant such as CO_2 is not a "pollutant subject to regulation" if the CAA did not require actual control of emissions of the pollutant. Moreover, this interpretation has been applied expressly to CO_2. The U.S. EPA's interpretation has been laid out in several guidance memoranda. For example, in a memorandum dated April 26, 1993 from Lydia N. Wegman, of U.S. EPA's Office of Air Quality Planning and Standards, to U.S. EPA's Regional Air Directors, it is specifically considered whether CO_2 was subject to regulation. The memorandum states that, although the 1990 amendments to the Clean Air Act included provisions addressing CO_2 and methane, "these requirements involve actions such as reporting and study, not actual control of emissions." The memorandum concluded, "if the results of these studies suggest the need for regulation, these pollutants could be reconsidered at that time for classification as pollutants subject to regulation under the Act."

More recently, in 2002, the U.S. EPA substantially revised its New Source Review ("NSR") Program and promulgated revised rules on December 31, 2002. 67 *Fed. Reg.* 80290 (December 31, 2002). The revised rules substituted a new defined term, "regulated NSR pollutant" for the Act's phrase "pollutant subject to regulation." The phrase "regulated NSR pollutant" expressly includes only pollutants (or substances) (i) for which a national ambient air quality standard has been promulgated, (ii) that are subject to new source performance standards ("NSPS"), (iii) subject to a standard under the stratospheric ozone protection program of Title VI of the CAA, or (iv) that otherwise is subject to regulation under the Act (but generally excluding hazardous air pollutants).

Indiana's definition is essentially a verbatim replication of the federal definition. The first three categories of the definition are similar in one aspect – they all provide for the development of substantive emission standards of the specified pollutants through a formal and comprehensive rulemaking approach. Carbon dioxide is not regulated under any of these three programs. This regulatory framework brings clarity to the fourth, catchall category, any pollutant "otherwise subject to regulation under the Act" (excluding hazardous air pollutants regulated under Section 112 of the Act). When viewed with the other three categories, it becomes clear that U.S. EPA did not intend the fourth category to include pollutants for which the Act does not require substantive emission limitations.

This approach is consistent with a canon of statutory interpretation known as *ejusdem generis,* which provides that, where general words of description follow an enumeration of persons or things described by words of a particular and specific meaning, the general words are not to be construed in their widest extent, but are to be understood as applying only to persons or things of the same class or kind as those specifically mentioned or listed. Moreover, when the U.S. EPA added the term "regulated NSR pollutant" to the NSR rules in 2002, it listed in the preamble to the rule all the pollutants that it believed where currently regulated under the CAA. This list did not include CO_2.

The U.S. Environmental Appeals Board ("EAB") has expressly held that CO_2 is not "subject to regulation." In *In re Inter-Power of New York, Inc.,* 5 E.A.D. 130, 151 (EAB 1994), the EAB held that the U.S. EPA was not required to conduct a BACT analysis for CO_2 and hydrogen chloride because they were "unregulated pollutants." In *In re Kawaihae Cogeneration Project,* 7 E.A.D. 107, 132 (EAB 1997) the EAB again reviewed whether the U.S. EPA should have included BACT limits for CO_2. The EAB held that no limits were necessary because CO_2 was not considered "a

regulated air pollutant for permitting purposes" because there were "no regulations or standards prohibiting, limiting, or controlling the emissions of greenhouse gases."

Therefore, carbon dioxide is not a regulated pollutant under Indiana law. IDEM does not have the jurisdiction to consider the effects of global warming caused by carbon dioxide. IDEM applies the air permitting rules contained in title 326 of the Indiana Administrative Code.

f. Alternative Sources of Energy
IDEM recognizes that the concerns expressed about the use of alternative sources of energy are important to those who expressed them. These concerns do not have a direct impact on how IDEM reviews and makes decisions on air permit applications. IDEM's permit review by law cannot address issues for which it does not have direct regulatory authority.

g. Tar Sand Mining and Related Refining
IDEM recognizes that the concerns expressed in opposition to mining tar sands are important to those who expressed them. These concerns do not have a direct impact on how IDEM reviews and makes decisions on air permit applications. IDEM's permit review by law cannot address issues for which it does not have direct regulatory authority.

h. BP's Environmental Record
IDEM recognizes that the concerns expressed regarding BP's possible liability for superfund cleanups are important to those who expressed them. These concerns do not have a direct impact on how IDEM reviews and makes decisions on air permit applications. IDEM's permit review by law cannot address issues for which it does not have direct regulatory authority.

i. Lake County Ambient Air Monitors
IDEM, OAQ conducts ambient air monitoring for ozone, course particulate matter, fine particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, lead and air toxics at locations around Indiana. The locations of these ambient air monitoring sites is described at http://www.in.gov/idem/programs/air/amb/index.html on the internet, with links to other pages that display the levels of concentration of each monitored pollutant. IDEM does an annual review of the monitoring network to insure optimal placement of the air monitors.

j. Schedule of Compliance
This issue is addressed in IDEM's response to EPA Comment No. 6 in the technical comment section above.

k. BP is a Foreign Corporation
IDEM recognizes that the concern expressed that BP is a foreign corporation whose profits will not go to Americans is important to those who expressed them. These concerns do not have a direct impact on how IDEM reviews and makes decisions on air permit applications. IDEM's permit review by law cannot address issues for which it does not have direct regulatory authority.

General Comment No. 3:

a. (RHAMC) Is BP contemplating expanding the refinery, for example, by purchased the NI Source Whiting Clean Energy Facility or any other emission units or sources not presently part of its permitted activities?

b. (Carolyn Marsh, Legal Environmental Aid Foundation) BP wants to buy the Whiting Clean Energy plant. Now they will be supplying steam to the refinery. When BP buys this plant, how is it going to impact the air pollution as well?

Response:

The Whiting Clean Energy plant is not considered part of the BP plant and is not considered in the processing of the current draft permits. IDEM has determined that these are separate sources pursuant to the definition of major source under 326 IAC 2-7-1(22). Based on this determination the operation of this facility will have no impact on the permitting of this project.

General Comment No. 4

(Save the Dunes Council) The Commenter recognizes and supports the air emissions that have been reduced by BP. However, many of the reductions were because of rules and regulations passed by EPA and the Indiana Air Pollution Control Board. How many of the reductions were beyond what was required by law?

Response:

The emission reductions relied upon for this netting analysis are beyond what is required by rule and/or regulation.

General Comment No. 5

IDEM's Permit Process
Several Commenters stated that IDEM has done a poor job in following the law and protecting the regions air quality, without concern for human health or the environment. Commenters stated that IDEM lacks morals, favors industry, is tramping on the little guy and behaves unethically. IDEM's job is to protect the public from pollution. IDEM should not give in to corporate greed. It is revolting that the agencies charged with protecting the public from the effects of pollution (IDEM and the EPA) would actually ignore their first priorities to accommodate the financial concerns of a discharger. This stinks of political interference from the notoriously pro-corporate administrations in Indianapolis and Washington, D.C. The center for Public Integrity recently reported this about the Centers for Disease Control and Prevention: A recent investigation by the Center for Public Integrity disclosed that the nation's top public health agency blocked the publication of an exhaustive federal study of environmental hazards in the eight Great lakes states, reportedly because it contained such potentially "alarming information" as evidence of elevated infant mortality and cancer rates. The Center reported that Chris De Rosa, a top government scientist with the Centers for Disease Control and Prevention, was demoted after he pushed the agency to publish the Great Lakes report and other studies. BP should be boycotted. If IDEM decides to go through with granting this permit IDEM can expect to be sued.

Response:

The BP permits include all applicable requirements found in both federal and state regulations and is protective of air quality. The notice of issuance of the permits contains information on how any person who does not agree with the final permits may petition the Indiana Office of Environmental Adjudication for review of the permits.

General Comment No. 6:

Even though the air we breathe is free and is not considered a natural resource does IDEM weigh in the moral and ethical responsibility it has to the environment and the community that surrounds the Whiting BP refinery for Environmental Justice issues of air space violations?

Response:

IDEM recognizes that these concerns are important to those who expressed them; however, they do not have a direct impact on how IDEM reviews and makes decisions on air permit applications. IDEM's permit review, by law, cannot address issues for which it does not have direct regulatory authority, such as air space violations.

General Comment No. 7 (Susan Eleuterio and Tom Sourlis)**:**

The Commenters state that IDEM's Office of Water Quality's mission is to monitor, protect and improve Indiana's water quality to ensure its continuous use as a drinking water source, habitat for wildlife, recreational resource, and economic asset. Why is there not a similar mission concerning Indiana's air quality?

Response:

IDEM's core mission is to protect human health and the environment while allowing for environmentally sound activities of industrial, agricultural, commercial and governmental operations vital to a prosperous economy. The Office of Air Quality's objectives are to improve air quality to meet the National Ambient Air Quality Standards and to reduce health risks; improve compliance rates; and provide quality, timely permit service.

General Comment No. 8 (Sauk-Calumet Sierra)**:**

The Commenter hereby requests that:

- BP quantify and make available to the general public current and projected greenhouse gas emissions for the years 2008 (base), 2018, 2028.
- BP consider voluntarily setting stricter standards for greenhouse gas emissions.
- BP consider voluntarily setting stricter standards for regulated air pollutants not limited to particulate matter, sulfur dioxide, hydrogen sulfide, lead.
- BP become a leader in finding solutions to and preventing global warming.

Response:

IDEM recognizes that these concerns are important to those who expressed them; however, they do not have a direct impact on how IDEM reviews and makes decisions on air permit applications. IDEM's permit review by law cannot address issues for which it does not have direct regulatory authority.

General Comment No. 9:

a. (Save the Dunes Council) Why was the Public Hearing scheduled on a Friday night during the winter? The Public Hearing was disappointing due to the lack of professionalism during the conduct of the hearing. It was a hostile situation without enough police to make people safe.

b. (Kurt Oldenbrook, IN) The public meeting was stacked with BP employees and their families. Most were probably paid to be there. This is and has been a common occurrence in Indiana for the last half century.

Response:

The public meeting and public hearing were scheduled on a day that a local facility large enough to hold the expected number of people was available. Over 1,000 people attended the meeting and hearing. The meeting and hearing were conducted in an orderly and efficient manner. Every

person who wished to speak was able to do so. Law enforcement officers were present inside and outside the facility and they maintained the peace. All persons, no matter their relationship to the source, are invited to attend and participate in IDEM public meetings and public hearings.

General Comment No. 10 (Save the Dunes Council):

The Commenter supports the permanent shutdown of the sludge incinerator and pointed out during the water permitting that this was a source of mercury that should be eliminated.

Response:

IDEM acknowledges this comment.

General Comment No. 11:

a. Lake Michigan Water Quality
Many commenters expressed concern regarding the impact of emissions from BP and other industries on the waters of Lake Michigan and its tributaries. Noting the value of these fresh water resources for drinking water and recreation, the commenters urged IDEM to not allow BP and other industries to destroy the water quality of Lake Michigan. The commenters stated that IDEM should not spoil a potential source of revenue to grant variances to industrial giants.

b. Truck Traffic
Commenter urges IDEM to deny BP's request for an air emissions permit for their planned $3.8 billion expansion of the Whiting refinery. Commenter stated that residents do not need a fleet of trucks, driving down our highways hauling asphalt products and most likely oozing asphalt vapors (volatile organic compounds) stinking up the air.

c. Refinery Odor and Improper Disposal
Commenters noted that on or around March 19, 2008, there was an undetermined amount of naphtha that escaped from the refinery that panicked residents for over 20 miles away. Why doesn't IDEM have odor and noise regulations for industry? Other commenters noted other odors from BP and from other area industry. Recently, BP has made national news for the improper disposal of the side-products of gas refining into Lake Michigan. Should an outfit that is so careless really be permitted to expand, let alone continue? It is time to make moral decisions, instead of economic ones.

Response:

IDEM recognizes that these concerns are important to those who expressed them; however, they do not have a direct impact on how IDEM reviews and makes decisions on air permit applications. IDEM's air permit review by law can address only issues that are part of the air pollution control regulations. Truck traffic and truck air emissions outside of the BP property are not subject to IDEM's air permitting process. IDEM does not regulate noise or odor. However, odor can be an indication that a process is not operating correctly. Citizens should report the details of any unusual odor to IDEM's air compliance inspector Ramesh Tejuja at IDEM's Northwest Regional Office, (219) 757-0282. The BP permits contain specific compliance determination requirements, compliance monitoring requirements, record keeping requirements and reporting requirements to insure that BP is in continuing compliance with all applicable regulations.

General Comment No. 12:

a. Texas City Explosion

Several Commenters stated that BP's plant in Texas City, Texas had an explosion three years ago that resulted in 15 deaths and more than 170 injuries. The U.S. Chemical Safety and Hazard Investigation Board released a video "Anatomy of a Disaster" that examines causes of the blast. The video states that years of budget cuts paved the way for the tragedy by limiting training, reducing staff and deferring maintenance and upgrades. BP continues to dispute that finding and has said the company found no link between cost cuts and the disaster. BP agreed to pay a 373 million dollar fine and admit criminal wrongdoing. BP does not have a good safety record in Texas City, Texas therefore I see no reason to trust BP with the safety of the people in Whiting.

b. OSHA Penalty
OSHA has fined the Whiting plant $384,250 for fines in violations. The Whiting Clean Energy plant, owned by NiSource, had a crash, chalking up 32.8 million dollars in losses.

Response:

IDEM recognizes that these concerns are important to those who expressed them; however, they do not have a direct impact on how IDEM reviews and makes decisions on air permit applications. IDEM's permit review, by law, cannot address issues for which it does not have direct regulatory authority. The BP permits contain specific compliance determination requirements, compliance monitoring requirements, record keeping requirements and reporting requirements to insure that BP is in continuing compliance with all applicable regulations.

OSHA (Occupational Safety and Health Administration) federal regulations cover most private sector workplaces. Its mission is to prevent work-related injuries, illnesses, and deaths by issuing and enforcing rules (called standards) for workplace safety and health. IDEM's permit review, by law, cannot address issues for which it does not have direct regulatory authority.

General Comment No. 13 (Margaret Laney, Aurora, IL):

We understand that the modernization project at Whiting will increase greenhouse gas emissions upon completion in 2011, as the facility will be processing more Canadian crude oil. Greenhouse gas emissions are a global issue, which is why BP is advocating for a single, mandatory, U.S. federal greenhouse gas emissions registry and a national cap and trade program. BP also supports development of policies to promote technological innovation and the growth of low-carbon businesses. It is not appropriate for the pending IDEM air permits to address greenhouse gas emissions because there not an appropriate regulatory program in place today to serve as the basis.

Response:

IDEM acknowledges this comment.

General Comment No. 14 (Thomas M. McDermott, Jr., Mayor, City of Hammond):

Based on the comments received during the public comment period, the Commenter knows that IDEM will now take a second look at the proposed permits to determine if any changes or modifications are necessary. The Commenter hopes that the data provided in BP's permit applications, and the comments made by the public will be incorporated into the final permits. In addition, the Commenter requests that once the permits are issued they be closely monitored so that the predicted environmental benefits will be realized in the timeframes set out in the approved permits.

Response:

IDEM considers all written comments, whether they are submitted in hardcopy or electronically. Under Indiana's air permit rules, IDEM determines if changes to the draft permit are warranted. IDEM believes that the specific compliance determination requirements, compliance monitoring requirements, record keeping requirements and reporting requirements as included in the final permits will ensure compliance with the emission limitations and standards set forth in the permits.

General Comment No. 15

(Carolyn Marsh, Legal Environmental Aid Foundation) Neither Whiting nor East Chicago has departments of environmental management. Will IDEM increase the number of employees in the region to monitor and react quickly to any mishaps and accidents at the refinery?

Response:

IDEM has a regional office located in Merrillville, Indiana. The compliance inspectors responsible for this facility work at this office and are therefore within a reasonable distance to respond promptly to compliance issues identified by local citizens. Citizens can contact IDEM's air compliance inspector, Ramesh Tejuja, at the Northwest Regional Office, by calling (219) 757-0282.

General Comment No. 16 (Georg Smolka)

If the CAFE standards had been improved instead of allowing MPG values for cars in this country to continue to drop, a lot of this necessity for oil would not be here.

Response:

OAQ recognizes that these concerns are important to those who expressed them; however, they do not have a direct impact on how IDEM reviews and makes decisions on air permit applications. IDEM, OAQ's permit review by law cannot address issues for which it does not have direct regulatory authority. All requirements for new vehicle fuel economy are set by the U.S. EPA.

Indiana Department of Environmental Management
Office of Air Quality

Appendix A to the
Addendum to the Technical Support Document (TSD) for a
Significant Source Modification (SSM) of a Part 70 Source and
Significant Permit Modification (SPM) of Part 70 Operating Permit

Rule Applicability Determination
(Response to EPA Comment # 4)

BP Products North America Inc., Whiting Business Unit
Significant Source Modification No.: 089-25484-00453
Significant Permit Modification No.: 089-25488-00453

BP Whiting Refinery
Air Regulatory Applicability

Tilte V Permit Section	Unit ID	Process Unit	Abbreviation	Applicable Requirements																														
				Equipment Leaks																								Waste Operations			Particulate			
				Leaks from Petroleum Refineries, 326 IAC 8-4-8	40 CFR 60 Subpart GGG/VV	40 CFR 60 Subpart GGGa/Vva	40 CFR 61Subpart J/V Benzene	40 CFR 63 Subpart CC Refinery MACT	40 CFR 60 Subpart UU, NSPS Asphalt	40 CFR 61 Subpart M, Asbestos	VOC from Pet. Refineries IAC 4-1 and 8-4-2	VOC for Tanks, 326 IAC 8-4-3 and 8-9	VOC for Organic solvent degreaser 326 IAC 8-3-2 and 8-3-5	VOC for Gasoline Dispensing Facility 326 IAC 8-4-6(b)	VOC for Bulk Gas Terminals and Equipment Leaks, 326 IAC 8-4-4 and 8-4-9	Continuous Monitoring of Emissions 326 IAC 3-5	40 CFR 60 Subpart K, Ka, Kb Storage Tanks	40 CFR 63 Subpart EEEE Organic Liquid Distribution MACT	40 CFR 60 Subpart J Petroleum Refineries	40 CFR 60 Subpart XX Bulk Gasoline Terminals	MACT 40 CFR 63 Y Marine Tank Loading Operations	NOx Trading Program, 326 IAC 10-4 or 326 IAC 24-3	Refinery MACT II 40 CFR 63 Subpart UUU	Remediation MACT 40 CFR 63 Subpart GGGGG	VOC Reductions, 326 IAC 8-7	40 CFR 60 Subpart Db Boilers	40 CFR 60 Subpart IIII, IC Engines	40 CFR 60 Subpart QQQ Refinery Wastewater Systems	40 CFR 63 Subpart DD Off-Site Waste and Recovery	40 CFR 61 Subpart FF Benzene Waste Operations	Opacity, 326 IAC 6.8-10 Fugitive Dust	Opacity, 326 IAC 5-1-2(2)(B) & (C) and 5-1-3	PM_{10} SIP, 6.8-2-6, 6.8-6-3, and 6.8-1-2	SO_2 SIP, 326 IAC 7-4.1-3
D.1	120	**No. 11 Pipestill**	11A&C PS	X	2	X[3]	4	X	7	X	X	6	36	37	38	X	8	27	X	29	30	24	23	31	32	33	34	X	25	X	15	X	X	X
D.2	120	**No. 11 Pipestill Coker**	11B PS	X	X	X	4	X	7	X	9	X	36	37	38	X	8	27	X	29	30	24	23	31	32	33	34	X	25	X	X	X	X	X
D.3	130	**No. 12 Pipestill**	12PS	X	X	26	4	X	7	X	X	6	36	37	38	X	8	27	X	29	30	24	23	31	32	33	34	X	25	X	15	X	X	X
D.4	162	**Sulfur Recovery Unit**	SRU	X[1]	1	26	4	5	7	X	9	X	36	37	38	X	8	27	X	29	30	24	X	31	32	33	34	X	25	13	15	X	X	X
D.5	241	**Vapor Recovery Units 200 & 100**	VRU 100 VRU 200	X	1	X[3]	4	X	7	X	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	X	25	X	15	35	16	16
D.6	150	**Vapor Recovery Unit 300**	VRU 300	X	1	26	4	X	7	X	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	X	25	X	15	35	16	16
D.6	150	**Vapor Recovery Unit 400**	VRU 400	X	22	X	4	X	7	X	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	X	25	X	15	35	16	16
D.7	140	**Alkylation Unit**	ALKY	X	X	26	4	X	7	X	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	X	25	13	15	35	16	16
D.8	145	**Propylene Concentration Unit**	PCU	X	1	X[3]	4	X	7	X	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	12	25	13	15	35	16	16
D.9	210	**Isomerization Unit**	ISOM	X	1	X[3]	4	X	7	X	9	6	36	37	38	X	8	27	X[2]	29	30	24	23	31	32	33	34	12	25	X	15	X	X	X
D.10	242	**Aromatic Recovery Unit**	ARU	X	1	X[3]	X	X	7	X	9	6	36	37	38	X	8	27	X[2]	29	30	24	23	31	32	33	34	12	25	X	15	X	X	X
D.11	250	**Blending Oil Unit**	BOU	X	1	26	4	X	7	X	9	6	36	37	38	X	8	27	X[2]	29	30	24	23	31	32	33	34	X	25	X	15	X	X	X
D.12	601	**#2 Treating Plant**	2TP	X	1	26	4	X	7	X	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	X	25	X	15	35	16	16
D.13	602	**#4 Treating Plant**	4TP	X	1	26	4	X	7	X	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	X	25	X	15	35	16	16
D.14	604	**Butane, Propane, and Propylene Storage and Loading Facilities**	Light ends	X	1	26	4	X	7	X	9	X	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	12	25	13	15	35	16	16
D.15	220	**No. 3 Ultraformer**	3UF	X	1	26	4	X	7	X	9	6	36	37	38	10	8	27	11	29	30	24	X	31	32	33	34	X	25	X	15	35	16	16
D.16	224	**No. 4 Ultraformer**	4UF	X	1	X[3]	4	X	7	X	9	6	36	37	38	X	8	27	X[2]	29	30	24	X	31	32	33	34	X	25	X	15	X	X	X
D.17	698	**Hydrogen Unit**	HU	X	X	26	4	X	7	X	9	6	36	37	38	X	8	27	X	29	30	24	23	31	32	33	34	X	25	13	15	X	X	X
D.18	700	**Distillate Desulfurization Unit**	DDU	X	X	X[3]	4	X	7	X	9	6	36	37	38	X	8	27	X	29	30	24	23	31	32	33	34	X	25	X	15	X	X	X
D.19	171	**Catalytic Feed Hydrotreating Unit**	CFU	X	X	26	4	X	7	X	9	6	36	37	38	X	8	27	X[2]	29	30	24	23	31	32	33	34	X	25	X	15	X	X	X
D.20	201	**Catalytic Refining Unit**	CRU	X	X	26	4	X	7	X	9	6	36	37	38	X	8	27	X[2]	29	30	24	23	31	32	33	34	12	25	X	15	X	X	X
D.21	230	**Fluidized Catalytic Cracking Unit 500**	FCU 500	X	1	X[3]	4	X	7	X	9	6	36	37	38	X	8	27	28	29	30	24	X	31	32	33	34	X	25	X	15	X	X	X
D.22	240	**Fluidized Catalytic Cracking Unit 600**	FCU 600	X	20, 1	X[3]	4	X	7	X	9	6	36	37	38	X	8	27	20, 28	29	30	24	X	31	32	33	34	12	25	X	15	X	X	X
D.23	501	**No. 1 Stanolind Power Station**	1SPS	X	1	26	4	X	7	X	9	6	36	37	38	X	8	27	X[2]	29	30	X	23	31	32	33	34	X	25	13	15	X	X	X
D.24	503	**No. 3 Stanolind Power Station**	3SPS	X	1	X[3]	4	X	7	X	9	6	36	37	38	X	8	27	X[2]	29	30	X	23	31	32	33	34	X	25	13	15	X	X	X
D.25	510	**Hazardous Waste Treatment Facility**		X	22	X	4	X	7	X	X	6	36	37	38	X[1]	8	27	X	29	30	24	23	31	32	33	34	X	25	X	15	X	X	16
D.26	544	**Wastewater Treatment Plant**	WWTP	21	1	26	4	X, 21	7	X	X	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	X	25	X	15	X	16	16
D.27	640	**Oil Movement**	OM	X	1	26	X	X	39	X	X	X	36	37	38	10	X	X	11	29	30	24	23	31	32	33	34	X	25	X	15	X	16	16
D.27	640	**J&L Tank Field**	J&L	X	X	26	X	X	7	X	9	X	36	37	38	10	X	27	11	29	30	24	23	31	32	33	34	X	25	X	15	X	16	16
D.28	999	**Remediation System**	Remed	22	1	26	4	22	7	X	9	6	36	37	38	10	8	27	X	29	30	24	23	X	X	33	34	12	25	13	15	X	16	16
D.29	693	**Mechanical Shop**	Mech	X	1	26	4	X	7	X	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	12	25	13	15	X	16	16
D.30		**Marketing Terminal**	Terminal	22	1	26	4	X	7	X	9	6	36	37	X	10	8	27	11	X	30	24	23	31	32	33	34	12	25	13	15	X	X	16
D.31		**Cooling Towers**	CT	3	1	26	4	5	7	X	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	12	25	13	15	X	16	16
D.32		**Asphalt**	Asphalt	X	X	X	4	X	X	X	9	X	36	37	38	10	8	27	X	29	30	24	23	31	32	33	34	12	25	13	15	X	X	X
D.33		**Cogen Steam Transfer Line**	Cogen	3	1	26	4	5	7	X	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	12	25	13	15	35	16	16
D.34		**Marine Dock Facility**	Dock	X	1	26	4	X	7	X	9	X	36	37	38	10	X	27	11	29	X	24	23	31	32	33	34	12	25	X	15	X	X	16
D.35		**Flares**	Flares	22	X	26	X	X	7	X	9	6	36	37	38	10	8	27	X	29	30	24	X	31	32	33	34	12	25	13	15	X	16	16
D.35		**Flares - GOHT and South**	Flares	22	22	X	4	X	7	40	9	6	36	37	38	10	8	27	X	29	30	24	23	31	32	33	34	12	25	13	15	X	16	16
D.36		**OSBL**	OSBL	X	1	X[3]	4	X	7	X	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	X	X	X	15	35	16	16
D.37		**Distillate Hydrotreating Unit**	DHT	X	X	26	4	X	7	X	9	6	36	37	38	X	8	27	11	29	30	24	23	31	32	33	34	X	25	X	15	X	X	X
D.38		**Degreasing Activities**		3	1	26	4	5	7	X	9	6	X	37	38	10	8	27	11	29	30	24	23	31	32	33	34	12	25	13	15	35	16	16
D.39		**Fuel Dispensing**		22	1	26	4	5	7	X	9	6	36	X	38	10	8	27	11	29	30	24	23	31	32	33	34	12	25	13	15	35	16	16
D.40		**Calumet Warehouse**		3	1	26	4	5	7	X	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	34	12	25	13	15	X	X	16
D.41		**Tank Cleaning Project**		X	1	26	4	X	7	40	9	X	36	37	38	10	8	27	X	29	30	24	23	31	32	33	34	12	25	13	15	X	X	16
D.42		**Gas Oil Hydrotreating Unit**	GOHT	X	22	X	4	X	7	40	9	6	36	37	38	X	8	27	X	29	30	24	23	31	32	33	34	X	25	X	15	X	X	16
D.43		**New Hydrogen Unit**	New HU	X	22	X	4	X	7	40	9	6	36	37	38	X	8	27	X	29	30	24	23	31	32	33	34	12	25	13	15	X	X	16
D.44		**New Boilers**		X	22	X	4	X	7	40	9	6	36	37	38	X	8	27	X	29	30	X	23	31	32	X	34	X	25	13	15	X	X	16
D.45		**Firepump Engines**		3	1	26	4	5	7	40	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	X	12	25	13	15	X	X	16
D.45		**Concrete Crusher**		3	1	26	4	5	7	40	9	6	36	37	38	10	8	27	11	29	30	24	23	31	32	33	X	12	25	13	X	X	X	16

Not included in Draft Permit

See attached "Footnotes".

Last Updated: 03/21/2008

BP Whiting Refinery
Air Regulatory Applicability

Footnotes:

X	Regulation is applicable to unit.
X[1]	Applicability only to fuel gas system on unit.
X[2]	Previously exempt due to age of unit, now required per Consent Decree.
X[3]	All or part of the process equipment covered by this section may be subject to this regulation. Applicability to be determined during construction of OCC Project.
1	No affected facilities (compressor, "equipment") constructed or modified after Jan 4, 1983 per 40 CFR 60.590(b).
2	Modification of affected facilities does not meet definition under 40 CFR 60.590(c).
3	Unit does not have equipment (i.e. pumps, valves, etc.) in VOC service.
4	Unit does not have equipment that contains or contacts a fluid (liquid or gas) w/ $\geq$10% wt benzene.
5	Unit does not contain equipment w/ > or = 5% HAPs, no controls required.
6	Unit does not have volatile organic liquid storage vessels or petroleum liquid storage vessels subject to 8-4-3 or 8-9.
7	Unit does not manufacture or store asphalt.
8	No affected facilities (i.e. petroleum or volatile organic liquid storage tanks) constructed or modified after June 11, 1973.
9	Unit does not have a vacuum system or wastewater separator (oil/water).
10	Unit does not have a CEM.
11	Does not meet applicability per 40 CFR 60.100.
12	No affected facilities constructed or modified after May 4, 1987 per 40 CFR 60.690(a)(1) or all Group 1 wastewater streams controlled per 40 CFR 61 Subpart FF.
13	Accounted under 6BQ exemption per 40 CFR 61.342(e).
14	Reserved.
15	Facilities not included in 326 IAC 6.8-10.
16	Unit does not have an emission source covered under PM and/ or SO2 SIP rule.
17	Reserved.
18	Reserved.
19	Reserved.
20	Per 40 CFR 60.14(e)(5) - the addition of a pollution control device would not be a modification.
21	Unit does not have process streams, only wastewater.
22	Unit is subject to another rule.
23	Not applicable per 40 CFR 63 Subpart UUU.
24	Unit does not have equipment subject to the NOx budget trading program in 326 IAC 10-4 or 326 IAC 24-3.

Last Updated: 03/21/2008

25 All off-site waste water processed on the refinery properties meets the exemption under 40 CFR 63 Subpart DD (per 40 CFR 63.680(d)). The total quantity of HAP is monitored and remains below 1 mega gram per year.
26 No affected facilities (compressor, "equipment") constructed or modified after Nov. 7, 2006 per 40 CFR 60.590a(b).
27 This unit does not have any organic liquid distribution operations per 40 CFR 63.2334 and 40 CFR 63.2338(c).
28 No affected facilities (i.e. fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device) constructed or modified after June 11, 1973.
29 Unit does not have equipment (i.e. gasoline loading racks) subject to 40 CFR 60, Subpart XX.
30 Unit does not have marine loading operations subject to 40 CFR 63, Subpart Y.
31 Unit does not have site remediation activities subject to 40 CFR 63, Subpart GGGGG.
32 Unit not subject to the specific VOC reduction requirements for Lake county in 326 IAC 8-7.
33 Unit does not have any equipment (i.e. boilers) constructed or modified after June 19, 1984.
34 Unit does not have any equipment (i.e. internal combustion engines) constructed or modified after July 11, 2005.
35 Unit does not have emissions of particulate matter.
36 Unit does not have a cold cleaning degreaser subject to 326 IAC 8-3-2 and 8-3-5.
37 Unit does not have gasoline dispensing operations subject to 326 IAC 8-4-6(b).
38 Unit does not have bulk gasoline terminal operations subject to 326 IAC 8-4-4 and 8-4-9.
39 Unit does not have affected facilities (asphalt storage tank) constructed or modified after May 26, 1981 per 40 CFR 60.470(b).
40 New units will not be subject to these requirements (i.e., not constructed with asbestos-containing material).

Indiana Department of Environmental Management
Office of Air Quality

Appendix C and E to the
Addendum to the Technical Support Document (TSD) for a
Significant Source Modification (SSM) of a Part 70 Source and
Significant Permit Modification (SPM) of Part 70 Operating Permit

Revised Calculations

BP Products North America Inc., Whiting Business Unit
Significant Source Modification No.: 089-25484-00453
Significant Permit Modification No.: 089-25488-00453

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Table C.1. Emission Factors for Carbon Monoxide Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	H-2	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	H-3	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
11C PS											
Cont	H-200	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	H-300	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Coker											
SD	H-101[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-102[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-103[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-104[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
New Coker (#2 Coker)											
New	H-201					0.019	lb/10[6] Btu	Design[4]	Guarantee[11]		0.019
New	H-202					0.019	lb/10[6] Btu	Design[4]	Guarantee[11]		0.019
New	H-203					0.019	lb/10[6] Btu	Design[4]	Guarantee[11]		0.019
12PS											
SD	H-1AN[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-1AS[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-1B[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-2[14]	0.0001	lb/10[6] Btu	Stack Test[3]	Source Specific[8]					0.0001	
SD	H-1CN[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-1CX[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
New	H-101A					0.019	lb/10[6] Btu	Design[4]	Guarantee[11]		0.019
New	H-102					0.019	lb/10[6] Btu	Design[4]	Guarantee[11]		0.019
New	H-101B					0.019	lb/10[6] Btu	Design[4]	Guarantee[11]		0.019
Hydroprocessing											
3UF											
SD	H-1[13]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-2[13]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	F-7[13]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
4UF											
Oth	F-1	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-8A	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-8B	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-2	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-3	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-4	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-5	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-6	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-7	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
ARU											
Oth	F-200A	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-200B	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
BOU											
Mod	F-401	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
CFHU											
Oth	F-801A	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-801B	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-801C	0.0001	lb/10[6] Btu	Stack Test[6]	Source Specific[8]	0.0001	lb/10[6] Btu	Stack Test[6]	Source Specific[8]	0.0001	0.0001
GOHT											
New	F-901A					0.02	lb/10[6] Btu	Design[4]	Guarantee[11]		0.02
New	F-901B					0.02	lb/10[6] Btu	Design[4]	Guarantee[11]		0.02
CRU											
Oth	F-101	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-102	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
DDU											
Oth	WB-301	0.04	lb/10[6] Btu	Permit Limit	Permit Limit[12]	0.04	lb/10[6] Btu	Permit Limit	Permit Limit[12]	0.04	0.04
Oth	WB-302	0.04	lb/10[6] Btu	Permit Limit	Permit Limit[12]	0.04	lb/10[6] Btu	Permit Limit	Permit Limit[12]	0.04	0.04
DHT											
New	B-601A					0.04	lb/10[6] Btu	Design[4]	Guarantee[11]		0.04
ISOM											
Mod	H-1	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
HU											
Oth	B-501	0.02	lb/10[6] Btu	Design[4]	Guarantee[11]	0.02	lb/10[6] Btu	Design[4]	Guarantee[11]	0.02	0.02
New HU (3rd Party SMR)											
New	HU-1[15]					0.015	lb/10[6] Btu	Design[4]	Guarantee[11]		0.015
New	HU-2[15]					0.015	lb/10[6] Btu	Design[4]	Guarantee[11]		0.015
Utilities											
1SPS											
SD	Boiler 3[13]	0.049	lb/10[6] Btu	Stack Test[1]	Source Specific[8]						
SD	Boiler 4[13]	0.049	lb/10[6] Btu	Stack Test[1]	Source Specific[8]						
SD	Boiler 5[13]	0.248	lb/10[6] Btu	Stack Test[1]	Source Specific[8]						
SD	Boiler 6[13]	0.248	lb/10[6] Btu	Stack Test[1]	Source Specific[8]						
SD	Boiler 7[13]	0.248	lb/10[6] Btu	Stack Test[1]	Source Specific[8]						
Fluidized Catalytic Cracking											
Oth	FCU 500	26	PPM	CEMS[5]	Source Specific[8]	42	PPM	CEMS	Source Specific[10]	N/A	N/A
Mod[16]	FCU 600	22	PPM	CEMS[5]	Source Specific[8]	41	PPM	CEMS	Source Specific[10]	N/A	N/A
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	Beavon-Stretford Tail Gas Unit[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	SRU Incinerator[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
New	New COT 1					0.05	lb/10[6] Btu	Design[4]	Guarantee[11]		0.05
New	New COT 2					0.05	lb/10[6] Btu	Design[4]	Guarantee[11]		0.05
New Flares											
New	GOHT Flare: Pilot					84	lb/10[6] scf	AP-42[2]	EF B Rating[9]		0.082
New	GOHT Flare: Purge					0.37	lb/10[6] Btu	AP-42[7]	EF B Rating[9]		0.37
New	South Flare: Pilot					84	lb/10[6] scf	AP-42[2]	EF B Rating[9]		0.082
New	South Flare: Purge					0.37	lb/10[6] Btu	AP-42[7]	EF B Rating[9]		0.37
New	HU Flare: Pilot					84	lb/10[6] scf	AP-42[2]	EF B Rating[9]		0.082
Lakefront											
SD	FBI (99-01)	0.1	lb/unit feed	Stack Test	Source Specific[8]					N/A	
SD	FBI (02-04)	0.012	lb/unit feed	Stack Test	Source Specific[8]					N/A	

Emission Factor Source References

[1] Based on stack test performed for BP Whiting Refinery in March 1993.
[2] U.S. AP-42. EPA. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4, "Natural Gas Combustion," Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NOx) AND CARBON MONOXIDE
[3] Based on stack test performed for BP Whiting Refinery in March 2002.
[4] Based on design requirements.
[5] Baseline actual emissions calculated using CEMS data for 2002-2004. Emissions prior to 2002 were conservatively calculated using minimum (annually averaged) CEMS data from 2002-2004.
[6] Based on stack test performed for BP Whiting Refinery in September 2003.
[7] U.S. AP-42. EPA. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.5, "Industrial Flares" Table 13.5-1. EMISSION FACTORS FOR FLARE OPERATION; (September 1991).

Justification References

[8] Based on most current source specific data.
[9] The carbon monoxide (CO) emission factors from AP-42 are used in the refinery industry as a standard when source specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.
[10] Based on source specific data.
[11] Based on anticipated vendor guarantee to satisfy design requirement.
[12] Emission factor based on emission limit in Title V operating permit.

Emission Unit References

[13] Existing unit being shutdown within the CXHO project contemporaneous period.
[14] Existing unit being shutdown as part of CXHO project.
[15] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same CO emission factors.
[16] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.2. Emission Factors for Lead Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	H-2	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	H-3	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
11C PS											
Cont	H-200	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	H-300	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Coker											
SD	H-101[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-102[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-103[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-104[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
New Coker (#2 Coker)											
New	H-201					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	H-202					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	H-203					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
12PS											
SD	H-1AN[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-1AS[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-1B[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-2[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-1CN[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-1CX[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
New	H-101A					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	H-102					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	H-101B					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
Hydroprocessing											
3UF											
SD	H-1[4]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-2[4]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	F-7[4]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
4UF											
Oth	F-1	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-8A	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-8B	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-2	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-3	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-4	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-5	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-6	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-7	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
ARU											
Oth	F-200A	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-200B	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
BOU											
Mod	F-401	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
CFHU											
Oth	F-801A	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-801B	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-801C	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
GOHT											
New	F-901A					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	F-901B					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
CRU											
Oth	F-101	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-102	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
DDU											
Oth	WB-301	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	WB-302	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
DHT											
New	B-601A					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
ISOM											
Mod	H-1	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
HU											
Oth	B-501	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
New HU (3rd Party SMR)											
New	HU-1[6]					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	HU-2[6]					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
Utilities											
1SPS											
SD	Boiler 3[4]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	Boiler 4[4]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	Boiler 5[4]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	Boiler 6[4]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	Boiler 7[4]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
Fluidized Catalytic Cracking											
Oth	FCU 500	2.55E-04	lb/1000 lb coke burned	Industry Paper[3]		2.55E-04	lb/1000 lb coke burned	Industry Paper[3]		N/A	N/A
Mod[7]	FCU 600	2.55E-04	lb/1000 lb coke burned	Industry Paper[3]		2.55E-04	lb/1000 lb coke burned	Industry Paper[3]		N/A	N/A
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	Beavon-Stretford Tail Gas Unit[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	SRU Incinerator[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
New	New COT 1					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	New COT 2					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New Flares											
New	GOHT Flare: Pilot					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	GOHT Flare: Purge					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	South Flare: Pilot					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	South Flare: Purge					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	HU Flare: Pilot					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
Lakefront											
SD	FBI (99-01)	3.95E-06	lb/ton feed								
SD	FBI (02)	1.98E-05	lb/ Mgal feed								
SD	FBI (03)	1.98E-05	lb/ Mgal feed								
SD	FBI (04-06)	1.98E-05	lb/ Mgal feed								

Emission Factor Source References

[1] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4 "Natural Gas Combustion," Table 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION; (July 1998).

Justification References

[2] The Lead emission factors from AP-42 are used in the refinery industry as a standard when site specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.

[3] R. Bertrand and J. Siegell. Emission of Trace Compounds from Catalytic Cracking Regenerators, Environmental Progress (volume 21, No. 3). October 2002. Pages 163-167

Footnotes

[4] Existing unit being shutdown within the CXHO project contemporaneous period.

[5] Existing unit being shutdown as part of CXHO project.

[6] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same lead emission factors.

[7] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.3. Emission Factors for Mercury Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	H-2	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	H-3	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
11C PS											
Cont	H-200	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	H-300	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Coker											
SD	H-101[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-102[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-103[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-104[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
New Coker (#2 Coker)											
New	H-201					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	H-202					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	H-203					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
12PS											
SD	H-1AN[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-1AS[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-1B[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-2[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-1CN[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-1CX[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
New	H-101A					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	H-102					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	H-101B					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
Hydroprocessing											
3UF											
SD	H-1[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-2[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	F-7[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
4UF											
Oth	F-1	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-8A	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-8B	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-2	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-3	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-4	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-5	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-6	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-7	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
ARU											
Oth	F-200A	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-200B	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
BOU											
Mod	F-401	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
CFHU											
Oth	F-801A	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-801B	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-801C	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
GOHT											
New	F-901A					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	F-901B					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
CRU											
Oth	F-101	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-102	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
DDU											
Oth	WB-301	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	WB-302	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
DHT											
New	B-601A					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
ISOM											
Mod	H-1	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
HU											
Oth	B-501	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
New HU (3rd Party SMR)											
New	HU-1[6]					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	HU-2[6]					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
Utilities											
1SPS											
SD	Boiler 3[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	Boiler 4[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	Boiler 5[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	Boiler 6[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	Boiler 7[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
Fluidized Catalytic Cracking											
Oth	FCU 500	1.00E-06	lb/1000 lb coke burned	Engineering Estimate[3]		1.00E-06	lb/1000 lb coke burned	Engineering Estimate[3]		N/A	N/A
Mod[7]	FCU 600	1.00E-06	lb/1000 lb coke burned	Engineering Estimate[3]		1.00E-06	lb/1000 lb coke burned	Engineering Estimate[3]		N/A	N/A
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	Beavon-Stretford Tail Gas Unit[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	SRU Incinerator[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
New	New COT 1					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	New COT 2					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New Flares											
New	GOHT Flare: Pilot					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	GOHT Flare: Purge					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	South Flare: Pilot					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	South Flare: Purge					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	HU Flare: Pilot					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
Lakefront											
SD	FBI (99-01)	2.7127E-05	lb/ton feed								
SD	FBI (02-06)	0.00013574	lb/Mgal feed								

Emission Factor Source References

[1] Emissions are based on API / WSPA Emission Factors for Boilers / Heaters using Process Gas, 1998 (Table ES-1).

Justification References

[2] Industry emission factor.

[3] Emission factor based on Engineering Estimate.

Footnotes

[4] Existing unit being shutdown within the CXHO project contemporaneous period.

[5] Existing unit being shutdown as part of CXHO project.

[6] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same mercury emission factors.

[7] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.4. Emission Factors for Beryllium Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	H-2	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	H-3	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
11C PS											
Cont	H-200	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	H-300	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Coker											
SD	H-101[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-102[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-103[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-104[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
New Coker (#2 Coker)											
New	H-201					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	H-202					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	H-203					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
12PS											
SD	H-1AN[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-1AS[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-1B[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-2[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-1CN[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-1CX[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
New	H-101A					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	H-102					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	H-101B					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
Hydroprocessing											
3UF											
SD	H-1[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-2[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	F-7[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
4UF											
Oth	F-1	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-8A	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-8B	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-2	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-3	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-4	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-5	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-6	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-7	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
ARU											
Oth	F-200A	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-200B	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
BOU											
Mod	F-401	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
CFHU											
Oth	F-801A	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-801B	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-801C	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
GOHT											
New	F-901A					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	F-901B					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
CRU											
Oth	F-101	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-102	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
DDU											
Oth	WB-301	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	WB-302	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
DHT											
New	B-601A					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
ISOM											
Mod	H-1	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
HU											
Oth	B-501	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
New HU (3rd Party SMR)											
New	HU-1[6]					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	HU-2[6]					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
Utilities											
1SPS											
SD	Boiler 3[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	Boiler 4[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	Boiler 5[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	Boiler 6[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	Boiler 7[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
Fluidized Catalytic Cracking											
Oth	FCU 500	3.51E-06	lb/1000 lb coke burned	Industry Paper[3]		3.51E-06	lb/1000 lb coke burned	Industry Paper[3]		N/A	N/A
Mod[7]	FCU 600	3.51E-06	lb/1000 lb coke burned	Industry Paper[3]		3.51E-06	lb/1000 lb coke burned	Industry Paper[3]		N/A	N/A
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	Beavon-Stretford Tail Gas Unit[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	SRU Incinerator[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
New	New COT 1					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	New COT 2					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New Flares											
New	GOHT Flare: Pilot					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	GOHT Flare: Purge					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	South Flare: Pilot					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	South Flare: Purge					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	HU Flare: Pilot					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
Lakefront											
SD	FBI (99-01)	1.64E-06	lb/ton feed								
SD	FBI(2003)	5.73E-06	lb/Mgal feed								
SD	FBI (02, 04 - 06)	8.22E-06	lb/Mgal feed								

Emission Factor Source References

[1] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4 "Natural Gas Combustion," Table 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION; (July 1998).

Justification References

[2] The Beryllium emission factors from AP-42 are used in the refinery industry as a standard when site specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.

[3] R. Bertrand and J. Siegell. Emission of Trace Compounds from Catalytic Cracking Regenerators, Environmental Progress (volume 21, No. 3). October 2002. Pages 163-167

Footnotes

[4] Existing unit being shutdown within the CXHO project contemporaneous period.

[5] Existing unit being shutdown as part of CXHO project.

[6] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same beryllium emission factors.

[7] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.5. Emission Factors for Nitrogen Oxides Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	0.166	lb/10^6 Btu	Stack Test[1]	Source Specific[12]	0.166	lb/10^6 Btu	Stack Test[1]	Source Specific[12]	0.166	0.166
Oth	H-2	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	0.098	0.098
Oth	H-3	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	0.098	0.098
11C PS											
Cont	H-200[21]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	0.05	lb/10^6 Btu	Design[10]	Guarantee[16]	0.275	0.05
Oth	H-300	0.137	lb/10^6 Btu	Stack Test[1]	Source Specific[12]	0.137	lb/10^6 Btu	Stack Test[1]	Source Specific[12]	0.137	0.137
Coker											
SD	H-101[18]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]					0.098	
SD	H-102[18]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]					0.098	
SD	H-103[18]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]					0.098	
SD	H-104[18]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]					0.098	
New Coker (#2 Coker)											
New	H-201					0.02	lb/10^6 Btu	Design[10]	Guarantee[16]		0.02
New	H-202					0.02	lb/10^6 Btu	Design[10]	Guarantee[16]		0.02
New	H-203					0.02	lb/10^6 Btu	Design[10]	Guarantee[16]		0.02
12PS											
SD	H-1AN[18]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]					0.275	
SD	H-1AS[18]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]					0.275	
SD	H-1B[18]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]					0.275	
SD	H-2[18]	0.036	lb/10^6 Btu	Stack Test[3]	Source Specific[12]					0.036	
SD	H-1CN[18]	100	lb/10^6 scf	AP-42[2]	EF A Rating[13]					0.098	
SD	H-1CX[18]	0.099	lb/10^6 Btu	Stack Test[1]	Source Specific[12]					0.099	
New	H-101A					0.05	lb/10^6 Btu	Design[10]	Guarantee[16]		0.050
New	H-102					0.05	lb/10^6 Btu	Design[10]	Guarantee[16]		0.050
New	H-101B					0.05	lb/10^6 Btu	Design[10]	Guarantee[16]		0.050
Hydroprocessing											
3UF											
SD	H-1[17]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]					0.275	
SD	H-2[17]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]					0.275	
SD	F-7[17]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]					0.098	
4UF											
Oth	F-1	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	0.098	0.098
Oth	F-8A	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	0.275	0.275
Oth	F-8B	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	0.275	0.275
Oth	F-2	190	lb/10^6 scf	AP-42[2]	EF A Rating[13]	190	lb/10^6 scf	AP-42[2]	EF A Rating[13]	0.186	0.186
Oth	F-3	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	0.275	0.275
Oth	F-4	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	0.275	0.275
Oth	F-5	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	0.098	0.098
Oth	F-6	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	0.098	0.098
Oth	F-7	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	0.098	0.098
ARU											
Oth	F-200A	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	0.275	0.275
Oth	F-200B	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	0.275	0.275
BOU											
Mod	F-401	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]	0.098	0.098
CFHU											
Oth	F-801A	50	lb/10^6 scf	AP-42[2]	EF D Rating[13]	50	lb/10^6 scf	AP-42[2]	EF D Rating[13]	0.049	0.049
Oth	F-801B	50	lb/10^6 scf	AP-42[2]	EF D Rating[13]	50	lb/10^6 scf	AP-42[2]	EF D Rating[13]	0.049	0.049
Oth	F-801C	0.036	lb/10^6 Btu	Stack Test[4]	Source Specific[12]	0.036	lb/10^6 Btu	Stack Test[4]	Source Specific[12]	0.036	0.036
GOHT											
New	F-901A					0.04	lb/10^6 Btu	Design[10]	Guarantee[16]		0.04
New	F-901B					0.04	lb/10^6 Btu	Design[10]	Guarantee[16]		0.04
CRU											
Oth	F-101	0.080	lb/10^6 Btu	Permit Limit[5]	Permit Limit[14]	0.080	lb/10^6 Btu	Permit Limit[5]	Permit Limit[14]	0.080	0.080
Oth	F-102	0.080	lb/10^6 Btu	Permit Limit[5]	Permit Limit[14]	0.080	lb/10^6 Btu	Permit Limit[5]	Permit Limit[14]	0.080	0.080
DDU											
Oth	WB-301	0.035	lb/10^6 Btu	Stack Test[1]	Source Specific[12]	0.035	lb/10^6 Btu	Stack Test[1]	Source Specific[12]	0.035	0.035
Oth	WB-302	0.030	lb/10^6 Btu	Stack Test[6]	Source Specific[12]	0.030	lb/10^6 Btu	Stack Test[6]	Source Specific[12]	0.030	0.030
DHT											
New	B-601A					0.04	lb/10^6 Btu	Design[10]	Guarantee[16]		0.040
ISOM											
Mod	H-1	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	280	lb/10^6 scf	AP-42[2]	EF A Rating[13]	0.275	0.275
HU											
Oth	B-501	0.068	lb/10^6 Btu	Stack Test[1]	Source Specific[12]	0.068	lb/10^6 Btu	Stack Test[1]	Source Specific[12]	0.068	0.068
New HU (3rd Party SMR)											
New	HU-1[19]					0.013	lb/10^6 Btu	Design[10]	Guarantee[16]		0.013
New	HU-2[19]					0.013	lb/10^6 Btu	Design[10]	Guarantee[16]		0.013
Utilities											
1SPS											
SD	Boiler 3[17]	0.157	lb/10^6 Btu	Stack Test[7]	Source Specific[12]					0.157	
SD	Boiler 4[17]	0.157	lb/10^6 Btu	Stack Test[7]	Source Specific[12]					0.157	
SD	Boiler 5[17]	0.093	lb/10^6 Btu	Stack Test[7]	Source Specific[12]					0.093	
SD	Boiler 6[17]	0.093	lb/10^6 Btu	Stack Test[7]	Source Specific[12]					0.093	
SD	Boiler 7[17]	0.093	lb/10^6 Btu	Stack Test[7]	Source Specific[12]					0.093	
Fluidized Catalytic Cracking											
Oth	FCU 500	40	ppm	Consent Decree[8]	Compliance with Consent Decree[15]	40	ppm	Consent Decree[8]	Compliance with Consent Decree[15]	N/A	N/A
Mod[21]	FCU 600	20	ppm	Consent Decree[9]	Compliance with Consent Decree[15]	20	ppm	Consent Decree[9]	Compliance with Consent Decree[15]	N/A	N/A
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[18]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]					0.098	
SD	Beavon-Stretford Tail Gas Unit[18]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]					0.098	
SD	SRU Incinerator[18]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]					0.098	
New	New COT 1					0.08	lb/10^6 Btu	Design[10]	Guarantee[16]		0.08
New	New COT 2					0.08	lb/10^6 Btu	Design[10]	Guarantee[16]		0.08
New Flares											
New	GOHT Flare: Pilot					100	lb/10^6 scf	AP-42[2]	EF B Rating[13]		0.098
New	GOHT Flare: Purge					0.068	lb/10^6 Btu	AP-42[11]	EF B Rating[13]		0.068
New	South Flare: Pilot					100	lb/10^6 scf	AP-42[2]	EF B Rating[13]		0.098
New	South Flare: Purge					0.068	lb/10^6 Btu	AP-42[11]	EF B Rating[13]		0.068
New	HU Flare: Pilot					100	lb/10^6 scf	AP-42[2]	EF B Rating[13]		0.098
Lakefront											
SD	FBI (99-01)	0.14	lb/unit feed	Source testing						N/A	
SD	FBI (02-06)	4.76	lb/Mgal FBI feed	Source testing						N/A	

Emission Factor Source References

[1] Based on stack test performed for BP Whiting Refinery.

[2] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4 "Natural Gas Combustion," Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NOx) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION SMALL BOILERS; (July 1998).

[3] Based on stack test performed for BP Whiting Refinery in March 2002.

[4] Based on stack test performed for BP Whiting Refinery in September 2003.

[5] Based on Permit Limit.

[6] Based on stack test performed for BP Whiting Refinery in January 2004.

[7] Based on stack test performed for BP Whiting Refinery in March 1993.

[8] NOx concentration limit from Consent Decree 4th Amendment, page 8 (United States, et.al v. BP Exploration & Oil, et. Al. Northern District of Indiana, Hammond Division Civil Action No. 2:96 CV 095 RL).

[9] NOx concentration limit from Consent Decree 4th Amendment, page 4 (United States, et.al v. BP Exploration & Oil, et. Al. Northern District of Indiana, Hammond Division Civil Action No. 2:96 CV 095 RL).

[10] Based on design requirement.

[11] U.S. AP-42. EPA. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.5, "Industrial Flares" Table 13.5-1. EMISSION FACTORS FOR FLARE OPERATION; (September 1991).

Justification References

[12] Based on most current source specific data.

[13] The Nitrogen Oxides (NOx) emission factors from AP-42 are used in the refinery industry as a standard when source specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.

[14] Emission factor based on emission limit in Draft Title V operating permit.

[15] Future emissions are assumed to be in compliance with Consent Decree. Baseline emissions were corrected to Consent Decree levels.

[16] Based on anticipated vendor guarantee to satisfy design requirement.

Emission Factor Source References

[17] Existing unit being shutdown within the CXHO project contemporaneous period.

[18] Existing unit being shutdown as part of CXHO project.

[19] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same NOX emission factors.

[20] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

[21] As part of the CXHO project, BP Whiting will be installing Ultra-Low NO_X burners on heater 11C PS H-200 to generate creditable emission reductions.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.6. Emission Factors for PM (Filterable) Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	H-2	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	H-3	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
11C PS											
Cont	H-200	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	H-300	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Coker											
SD	H-101[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-102[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-103[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-104[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
New Coker (#2 Coker)											
New	H-201					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	H-202					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	H-203					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
12PS											
SD	H-1AN[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-1AS[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-1B[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-2[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-1CN[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-1CX[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
New	H-101A					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	H-102					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	H-101B					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
Hydroprocessing											
3UF											
SD	H-1[10]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-2[10]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	F-7[10]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
4UF											
Oth	F-1	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-8A	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-8B	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-2	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-3	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-4	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-5	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-6	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-7	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
ARU											
Oth	F-200A	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-200B	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
BOU											
Mod	F-401	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
CFHU											
Oth	F-801A	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-801B	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-801C	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
GOHT											
New	F-901A					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	F-901B					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
CRU											
Oth	F-101	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-102	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
DDU											
Oth	WB-301	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	WB-302	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
DHT											
New	B-601A					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
ISOM											
Mod	H-1	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
HU											
Oth	B-501	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
New HU (3rd Party SMR)											
New	HU-1[12]					0.0068	lb/10^6 Btu	Design[5]	Guarantee[8]		0.0068
New	HU-2[12]					0.0068	lb/10^6 Btu	Design[5]	Guarantee[8]		0.0068
Utilities											
1SPS											
SD	Boiler 3[10]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	Boiler 4[10]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	Boiler 5[10]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	Boiler 6[10]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	Boiler 7[10]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
Fluidized Catalytic Cracking											
Oth	FCU 500	0.465	lb/10^3 lb coke burned	Stack Test[2]	Source Specific[9]	0.465	lb/10^3 lb coke burned	Stack Test[2]	Source Specific[9]	N/A	N/A
Mod[14]	FCU 600	0.35	lb/10^3 lb coke burned	Stack Test[2]	Source Specific[9]	0.35	lb/10^3 lb coke burned	Stack Test[2]	Source Specific[9]	N/A	N/A
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	Beavon-Stretford Tail Gas Unit[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	SRU Incinerator[11]	1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]					0.0019	
New	New COT 1					1.9	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0019
New	New COT 2					1.9	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0019
Cooling Towers											
Cont	Cooling Tower 2[3]	0.02%	liquid drift	AP-42[3]	EF E Rating[7]	0.001%	liquid drift	Design[4]	Guarantee[8]	N/A	N/A
		0.001%	liquid drift	Design[4]	Guarantee[8]	0.001%	liquid drift	Design[4]	Guarantee[8]	N/A	N/A
Cont	Cooling Tower 3	0.02%	liquid drift	AP-42[3]	EF E Rating[7]	0.001%	liquid drift	Design[4]	Guarantee[8]	N/A	N/A
Cont	Cooling Tower 4	0.02%	liquid drift	AP-42[3]	EF E Rating[7]	0.001%	liquid drift	Design[4]	Guarantee[8]	N/A	N/A
SD	SBS Cooling Towe[11]	0.02%	liquid drift	AP-42[3]	EF E Rating[7]					N/A	
New Cooling Towers											
New	Cooling Tower 7					0.001%	liquid drift	Design[5]	Guarantee[8]		N/A
New	Cooling Tower 8					0.001%	liquid drift	Design[5]	Guarantee[8]		N/A
New	HU Cooling Tower					0.001%	liquid drift	Design[5]	Guarantee[8]		N/A
New Flares											
New	GOHT Flare: Pilot					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	GOHT Flare: Purge					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	South Flare: Pilot					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	South Flare: Purge					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	HU Flare: Pilot					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
Fugitive Dust											
New	Transfer Point 1, 10					0.000880	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
New	Transfer Point 2 - 9					0.000880	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
New	Transfer Point 1,2,3 AOS					0.000880	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
New	Transfer Point 4 AOS					0.000880	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
SD	Aggregate Storage - Pile	0.49	lb/hr/acre	1988 EPA Report[6.1]						N/A	
SD	Aggregate Storage - Coke Yard	1.12	lb/hr/acre	1988 EPA Report[6.1]						N/A	
SD	Aggregate Handling	0.000645	lb/ton handled/transfer point	AP-42[6]	EF A Rating[7]					N/A	
SD	Paved Road Emissions	5.27	lb/VMT	AP-42[6.2]	EF A Rating[7]					N/A	
SD	Unpaved Road Emissions - Truck	7.70	lb/VMT	AP-42[6.3]	EF A Rating[7]					N/A	
SD	Unpaved Road Emissions - Front End Loader	10.23	lb/VMT	AP-42[6.3]	EF A Rating[7]					N/A	
Lakefront											
SD	FBI (99-01)	0.184	lb/unit feed	Source testing						N/A	
SD	FBI (02-06)	0.0255	lb/Mgal FBI feed	Source testing						N/A	

Emission Factor Source References

[1] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4 "Natural Gas Combustion," Table 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION; (July 1998).

[2] Based on stack test performed for BP Whiting Refinery in June 2005.

[3] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 13, Section 13.4, Wet Cooling Towers, Table 13.4-1 PARTICULATE EMISSION FACTORS FOR WET COOLING TOWERS; (January 1995).

[4] Based on material balance including average total dissolved solids and recirculation rates from 1999 to 2004 along with design requirements of drift eliminators.

[5] Based on design requirement.

[6] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.2.4 "Aggregate Handling and Storage Piles," Equation (1). (March 2006).

[6.1] Chapter 4 of the 1988 EPA Report "Control of Open Fugitive Dust Sources". (EPA - 450/3-88-008) Note Chapter 4 1988 EPA Report provides a method to calculate wind emissions from a continuously active pile. This is more representative of the aggregate storage at BP Whiting than the AP-42 Section 13.2.5 "Industrial Wind Erosion", which better represents discreet disturbances.

[6.2] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.2.1 "Paved Roads", Equation (1). (November 2006).

[6.2] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.2.2 "Unpaved Roads", Equation (1a). (November 2006).

Justification References

[7] The particulate matter (PM) emission factors from AP-42 are used in the refinery industry as a standard when site specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.
E - Poor - Developed from lower rated test data from a small number of facilities.

[8] Based on anticipated vendor guarantee to satisfy design requirement.

[9] Based on most current source specific data.

Emission Unit References

[10] Existing unit being shutdown within the CXHO project contemporaneous period.

[11] Existing unit being shutdown as part of CXHO project.

[12] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same particulate emission factors.

[13] Half of the Cooling Tower 2 modules were controlled by high efficiency drift eliminators in the baseline period.

[14] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.7. Emission Factors for PM_{10} and $PM_{2.5}$ (Filterable + Condensable) Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor[15]	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0075	0.0075
Oth	H-2	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0075	0.0075
Oth	H-3	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0075	0.0075
11C PS											
Cont	H-200	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0075	0.0075
Oth	H-300	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0075	0.0075
Coker											
SD	H-101[11]	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]					0.0040	
SD	H-102[11]	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]					0.0040	
SD	H-103[11]	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]					0.0040	
SD	H-104[11]	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]					0.0040	
New Coker (#2 Coker)											
New	H-201					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	H-202					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	H-203					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
12PS											
SD	H-1AN[11]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	H-1AS[11]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	H-1B[11]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	H-2[11]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	H-1CN[11]	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]					0.0040	
SD	H-1CX[11]	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]					0.0040	
New	H-101A					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	H-102					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	H-101B					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
Hydroprocessing											
3UF											
SD	H-1[10]	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]					0.0040	
SD	H-2[10]	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]					0.0040	
SD	F-7[10]	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]					0.0040	
4UF											
Oth	F-1	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-8A	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-8B	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-2	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-3	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-4	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-5	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-6	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-7	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
ARU											
Oth	F-200A	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-200B	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
BOU											
Mod	F-401	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
CFHU											
Oth	F-801A	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-801B	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-801C	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
GOHT											
New	F-901A					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	F-901B					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
CRU											
Oth	F-101	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-102	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
DDU											
Oth	WB-301	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	WB-302	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
DHT											
New	B-601A					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
ISOM											
Mod	H-1	0.004	lb/10^6 Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
HU											
Oth	B-501	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]	0.0075	0.0075
New HU (3rd Party SMR)											
New	HU-1[12]					0.0068	lb/10^6 Btu	Design[5]	Guarantee[9]		0.0068
New	HU-2[12]					0.0068	lb/10^6 Btu	Design[5]	Guarantee[9]		0.0068
Utilities											
1SPS											
SD	Boiler 3[10]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	Boiler 4[10]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	Boiler 5[10]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	Boiler 6[10]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	Boiler 7[10]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]					0.0075	
Fluidized Catalytic Cracking											
Oth	FCU 500	0.465	lb/10^3 lb Coke Burned	Stack Test[2]	Source Specific[8]	0.465	lb/10^3 lb Coke Burned	Stack Test[2]	Source Specific[8]	N/A	N/A
Mod[14]	FCU 600	0.35	lb/10^3 lb Coke Burned	Stack Test[2]	Source Specific[8]	0.35	lb/10^3 lb Coke Burned	Stack Test[2]	Source Specific[8]	N/A	N/A
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[11]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	Beavon-Stretford Tail Gas Unit[11]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	SRU Incinerator[11]	7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]					0.0075	
New	New COT 1					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	New COT 2					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
Cooling Towers											
Cont	Cooling Tower 2[13]	0.02%	liquid drift	AP-42[3]	EF E Rating[7]	0.001%	liquid drift	Design[4]	Guarantee[9]	N/A	N/A
		0.001%	liquid drift	Design[4]	Guarantee[9]	0.001%	liquid drift	Design[4]	Guarantee[9]	N/A	N/A
Cont	Cooling Tower 3	0.02%	liquid drift	AP-42[3]	EF E Rating[7]	0.001%	liquid drift	Design[4]	Guarantee[9]	N/A	N/A
Cont	Cooling Tower 4	0.02%	liquid drift	AP-42[3]	EF E Rating[7]	0.001%	liquid drift	Design[4]	Guarantee[9]	N/A	N/A
SD	SBS Cooling Tower[11]	0.02%	liquid drift	AP-42[3]	EF E Rating[7]					N/A	
New Cooling Towers											
New	Cooling Tower 7					0.001%	liquid drift	Design[5]	Guarantee[9]		N/A
New	Cooling Tower 8					0.001%	liquid drift	Design[5]	Guarantee[9]		N/A
New	HU Cooling Tower					0.001%	liquid drift	Design[5]	Guarantee[9]		N/A
New Flares											
New	GOHT Flare: Pilot					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	GOHT Flare: Purge					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	South Flare: Pilot					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	South Flare: Purge					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	HU Flare: Pilot					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
Fugitive Dust											
New	Transfer Point 1, 10					0.000416	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
New	Transfer Point 2 - 9					0.000416	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
New	Transfer Point 1,2,3 AOS					0.000416	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
New	Transfer Point 4 AOS					0.000416	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
SD	Aggregate Storage - Pile	0.24	lb/hr/acre	1988 EPA Report[6.1]						N/A	
SD	Aggregate Storage - Coke Yard	0.56	lb/hr/acre	1988 EPA Report[6.1]						N/A	
SD	Aggregate Handling	0.000305	lb/ton handled/transfer point	AP-42[6]	EF A Rating[7]					N/A	
SD	Paved Road Emissions	1.03	lb/VMT	AP-42[6.2]	EF A Rating[7]					N/A	
SD	Unpaved Road Emissions - Truck	2.29	lb/VMT	AP-42[6.3]	EF A Rating[7]					N/A	
SD	Unpaved Road Emissions - Front End Loader	3.04	lb/VMT	AP-42[6.3]	EF A Rating[7]					N/A	
Lakefront											
SD	FBI (99-01)	0.184	lb/unit feed	Source testing						N/A	
SD	FBI (02-06)	0.0255	lb/Mgal FBI feed	Source testing						N/A	

Emission Factor Source References

[1] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4 "Natural Gas Combustion," Table 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION; (July 1998).

[2] Based on stack test performed for BP Whiting Refinery in June 2005.

[3] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 13, Section 13.4, Wet Cooling Towers, Table 13.4-1 PARTICULATE EMISSION FACTORS FOR WET COOLING TOWERS; (January 1995).

[4] Based on material balance including average total dissolved solids and recirculation rates from 1999 to 2004 along with design requirements of drift eliminators.

[5] Based on design requirement.

[6] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.2.4 "Aggregate Handling and Storage Piles," Equation (1). (March 2006).

[6.1] Chapter 4 of the 1988 EPA Report "Control of Open Fugitive Dust Sources". (EPA - 450/3-88-008) Note Chapter 4 1988 EPA Report provides a method to calculate wind emissions from a continuously active pile. This is more representative of the aggregate storage at BP Whiting than the AP-42 Section 13.2.5 "Industrial Wind Erosion", which better represents discreet disturbances.

[6.2] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.2.1 "Paved Roads", Equation (1). (November 2006).

[6.2] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.2.2 "Unpaved Roads", Equation (1a). (November 2006).

Justification References

[7] The total particulate matter (PM) emission factors from AP-42 are used in the refinery industry as a standard when site specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.
E - Poor - Developed from lower rated test data from a small number of facilities.

[8] Based on anticipated vendor guarantee to satisfy design requirement.

[9] Based on most current source specific data.

Emission Unit References

[10] Existing unit being shutdown within the CXHO project contemporaneous period.

[11] Existing unit being shutdown as part of CXHO project.

[12] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same particulate emission factors.

[13] Half of the Cooling Tower 2 modules were controlled by high efficiency drift eliminators in the baseline period.

[14] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

[15] Based on interim guidance from US EPA, $PM_{2.5}$ is evaluated based on significant emission rate thresholds established for PM_{10}. The current PM_{10} SIP limits filterable PM_{10} emissions and compliance is based on reference test method 201A (which only quantifies filterable particulate matter). Although not required, BP Whiting has conservatively adjusted the PM_{10} baseline based on the PM_{10} SIP limits for PSD applicability purposes, which includes both filterable and condensable PM. $PM_{2.5}$ emissions are not regulated by the Lake County PM_{10} SIP, however, to be conservative, BP Whiting has adjusted $PM_{2.5}$ baseline emissions in the same manner as for PM_{10} emissions.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.8. Emission Factors for Sulfuric Acid Mist Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions			
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification
Crude and Coking									
11A PS									
Oth	H-1X	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	H-2	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	H-3	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
11C PS									
Cont	H-200	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	H-300	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Coker									
SD	H-101[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-102[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-103[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-104[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
New Coker (#2 Coker)									
New	H-201					See EF Reference[2]		CEMS[2]	Source Specific[4]
New	H-202					See EF Reference[2]		CEMS[2]	Source Specific[4]
New	H-203					See EF Reference[2]		CEMS[2]	Source Specific[4]
12PS									
SD	H-1AN[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-1AS[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-1B[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-2[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-1CN[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-1CX[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
New	H-101A					See EF Reference[2]		CEMS[2]	Source Specific[4]
New	H-102					See EF Reference[2]		CEMS[2]	Source Specific[4]
New	H-101B					See EF Reference[2]		CEMS[2]	Source Specific[4]
Hydroprocessing									
3UF									
SD	H-1[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-2[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	F-7[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
4UF									
Oth	F-1	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-8A	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-8B	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-2	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-3	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-4	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-5	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-6	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-7	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
ARU									
Oth	F-200A	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-200B	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
BOU									
Mod	F-401	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
CFHU									
Oth	F-801A	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-801B	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-801C	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
GOHT									
New	F-901A					See EF Reference[2]		CEMS[2]	Source Specific[4]
New	F-901B					See EF Reference[2]		CEMS[2]	Source Specific[4]
CRU									
Oth	F-101	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-102	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
DDU									
Oth	WB-301	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	WB-302	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
DHT									
New	B-601A					See EF Reference[2]		CEMS[2]	Source Specific[4]
ISOM									
Mod	H-1	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
HU									
Oth	B-501	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
New HU (3rd Party SMR)									
New	HU-1[7]					See EF Reference[2]		CEMS[2]	Source Specific[4]
New	HU-2[7]					See EF Reference[2]		CEMS[2]	Source Specific[4]
Code	**Process Unit**	**Baseline Actual Emissions**				**Future Potential Emissions**			
		Emission Factor	**Unit**	**Source**	**Justification**	**Emission Factor**	**Unit**	**Source**	**Justification**
Utilities									
1SPS									
SD	Boiler 3[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	Boiler 4[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	Boiler 5[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	Boiler 6[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	Boiler 7[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
Lakefront									
SD	FBI (99-01)	N/A							
SD	FBI (02-06)	N/A							

Emission Factor Source References

[1] Calculation based on sulfur dioxide (SO_2) emissions. SO_2 emissions were calculated using hydrogen sulfide (H_2S) CEMS data, and TRS testing data where available.

[2] Calculation based on future potential sulfur dioxide (SO_2) emissions. SO_2 emissions were calculated using the future design fuel gas total sulfur.

Justification References

[3] Based on baseline year source specific data (SO_2 emissions CEMS data).

[4] Based on future potential SO_2 emissions.

Emission Unit References

[5] Existing unit being shutdown within the CXHO project contemporaneous period.

[6] Existing unit being shutdown as part of CXHO project.

[7] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Only the combustion of natural gas will emit SO_2 and therefore sulfuric acid mist.

Calculation Methodology

Combustion emissions are assumed to include some amount of SO_3, which can react with water vapor present in the stack to produce sulfuric acid mist (H_2SO_4 mist) as shown in Equation C-8-1.

Equation C-8-1

$$SO_3 + H_2O \Leftrightarrow H_2SO_4$$

H_2SO_4 mist emissions are conservatively calculated by assuming 3% of the SO_X emitted by the heater is in the form of SO_3.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.9. Emission Factors for Sulfur Dioxide Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu			
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	2001	2002	Baseline	Future
Crude and Coking													
11A PS													
Oth	H-1X	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
Oth	H-2	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
Oth	H-3	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
11C PS													
Cont	H-200	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
Oth	H-300	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
Coker													
SD	H-101[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-102[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-103[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-104[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
New Coker (#2 Coker)													
New	H-201					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	H-202					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	H-203					80	ppm	CEMS[1]	Source Specific[10]				0.0111
12PS													
SD	H-1AN[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-1AS[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-1B[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-2[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-1CN[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-1CX[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
New	H-101A					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	H-102					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	H-101B					80	ppm	CEMS[1]	Source Specific[10]				0.0111
Hydroprocessing													
3UF													
SD	H-1[14]	42.12	ppm	CEMS[1]	Source Specific[8]					0.0113	0.0074	0.0094	
SD	H-2[14]	42.12	ppm	CEMS[1]	Source Specific[8]					0.0113	0.0074	0.0094	
SD	F-7[14]	42.12	ppm	CEMS[1]	Source Specific[8]					0.0113	0.0074	0.0094	
4UF													
Oth	F-1	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-8A	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-8B	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-2	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-3	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-4	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-5	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-6	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-7	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
ARU													
Oth	F-200A	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
Oth	F-200B	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
BOU													
Mod	F-401	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
CFHU													
Oth	F-801A	48.43	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0074	0.0128	0.0101	0.0111
Oth	F-801B	48.43	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0074	0.0128	0.0101	0.0111
Oth	F-801C	48.43	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0074	0.0128	0.0101	0.0111
GOHT													
New	F-901A					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	F-901B					80	ppm	CEMS[1]	Source Specific[10]				0.0111
CRU													
Oth	F-101	42.12	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0113	0.0074	0.0094	0.0111
Oth	F-102	42.12	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0113	0.0074	0.0094	0.0111
DDU													
Oth	WB-301	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
Oth	WB-302	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
DHT													
New	B-601A					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
ISOM													
Mod	H-1	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
HU													
Oth	B-501	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0703	0.0672	0.0687	0.0111
New HU (3rd Party SMR)													
New	HU-1[16]					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
						0	ppm	Process Design[13a]					0.0000
New	HU-2[16]					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
						0	ppm	Process Design[13a]					0.0000
Utilities													
1SPS													
SD	Boiler 3[14]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	Boiler 4[14]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	Boiler 5[14]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	Boiler 6[14]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	Boiler 7[14]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
Fluidized Catalytic Cracking													
Oth	FCU 500	25	ppm	Consent Decree[2]	Compliance with Consent Decree[9]	25	ppm	CEMS[5]	Source Specific[11]	N/A	N/A	N/A	N/A
Mod[17]	FCU 600	50	ppm	Consent Decree[3]	Compliance with Consent Decree[9]	37	ppm	CEMS[5]	Source Specific[11]	N/A	N/A	N/A	N/A
Sulfur Recovery Complex													
SD	SBS Tail Gas Unit[15]	0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]					0.0006	0.0006	0.0006	
SD	Beavon-Stretford Tail Gas Unit[15]	0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]					0.0006	0.0006	0.0006	
SD	SRU Incinerator[11]	0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]					0.0006	0.0006	0.0006	
New	New COT 1												
	Thermal Oxidizer					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
	Process					45	ppm	Design[7]	Guarantee[13]				N/A
New	New COT 2												
	Thermal Oxidizer					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
	Process					45	ppm	Design[7]	Guarantee[13]				N/A
New Flares													
New	GOHT Flare: Pilot					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
New	GOHT Flare: Purge					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	South Flare: Pilot					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
New	South Flare: Purge					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	HU Flare: Pilot					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
Lakefront													
SD	FBI (99-01)	0.13	lb/unit feed	Source testing						N/A	N/A	N/A	
SD	FBI (02-06)	0.0093	lb/Mgal FBI feed	Source testing						N/A	N/A	N/A	

Emission Factor Source References

[1] Baseline actual emissions calculated using Hydrogen sulfide (H_2S) CEMS data and TRS sampling. Future actual emissions based on CXHO design for total sulfur in the fuel gas.

[2] Sulfur dioxide (SO_2) concentration limit from Consent Decree 4th Amendment, page 9 (United States, et.al v. BP Exploration & Oil, et. al. Northern District of Indiana, Hammond Division Civil Action No. 2:96 CV 095 RL).

[3] SO_2 concentration limit from Consent Decree 4th Amendment, page 11 (United States, et.al v. BP Exploration & Oil, et. al. Northern District of Indiana, Hammond Division Civil Action No. 2:96 CV 095 RL).

[4] Baseline actual emissions calculated using H_2S and remaining Total Reduce Sulfur (TRS) CEMS data.

[5] Future SO_2 ppm based on anticipated operation to achieve future projected emission rate.

[6] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4 "Natural Gas Combustion," Table 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION; (July 1998).

[7] Based on design requirement.

Justification References

[8] Based on source specific data.

[9] Baseline emissions were corrected to Consent Decree levels.

[10] Based on future projected total sulfur in the fuel gas.

[11] Future projected emissions based on anticipated operation of FCU 500 and 600. 20 ppm concentration is the basis for the proposed tpy limit.

[12] The sulfur dioxide (SO2) emission factors from AP-42 are used in the refinery industry as a standard when site specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:

A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.
E - Poor - Developed from lower rated test data from a small number of facilities.

[13] Based on anticipated vendor guarantee to satisfy design requirement.

[13a] Inherent to the process design, the pressure swing adsorption (PSA) offgas does not contain any sulfur compounds.

Emission Unit References

[14] Existing unit being shutdown within the CXHO project contemporaneous period.

[15] Existing unit being shutdown as part of CXHO project.

[16] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Only combustion of natural gas produces SO_2 emissions.

[17] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.10. Emission Factors for Volatile Organic Compound Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	H-2	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	H-3	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
11C PS											
Cont	H-200	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	H-300	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Coker											
SD	H-101[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-102[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-103[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-104[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
New Coker (#2 Coker)											
New	H-201					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
New	H-202					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
New	H-203					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
12PS											
SD	H-1AN[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-1AS[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-1B[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-2[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-1CN[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-1CX[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
New	H-101A					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
New	H-102					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
New	H-101B					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
Hydroprocessing											
3UF											
SD	H-1[10]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-2[10]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	F-7[10]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
4UF											
Oth	F-1	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-8A	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-8B	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-2	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-3	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-4	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-5	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-6	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-7	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
ARU											
Oth	F-200A	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-200B	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
BOU											
Mod	F-401	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
CFHU											
Oth	F-801A	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-801B	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-801C	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
GOHT											
New	F-901A					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
New	F-901B					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
CRU											
Oth	F-101	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-102	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
DDU											
Oth	WB-301	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	WB-302	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
DHT											
New	B-601A					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
ISOM											
Mod	H-1	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
HU											
Oth	B-501	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[6]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
New HU (3rd Party SMR)											
New	HU-1[12]					0.0034	lb/10^6 Btu	Design[6]	Guarantee[9]		0.0034
New	HU-2[12]					0.0034	lb/106 Btu	Design[6]	Guarantee[9]		0.0034
Utilities											
1SPS											
SD	Boiler 3[10]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	Boiler 4[10]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	Boiler 5[10]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	Boiler 6[10]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	Boiler 7[10]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
Fluidized Catalytic Cracking											
Oth	FCU 500	220	lb/10^3 bbl of fresh feed	AP-42[2]	EF B Rating[7]	220	lb/10^3 bbl of fresh feed	AP-42[2]	EF B Rating[7]	N/A	N/A
Mod[14]	FCU 600	220	lb/10^3 bbl of fresh feed	AP-42[2]	EF B Rating[7]	220	lb/10^3 bbl of fresh feed	AP-42[2]	EF B Rating[7]	N/A	N/A
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	Beavon-Stretford Tail Gas Unit[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	SRU Incinerator[11]	5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]					0.0054	
New	New COT 1					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
New	New COT 2					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
Cooling Tower											
SD	SBS Cooling Tower	0.7	lb/10^6 gal cooling water	AP-42[3]	EF D Rating[7]					N/A	
New Cooling Towers											
New	Cooling Tower 7					0.7	lb/10^6 gal cooling water	AP-42[3]	EF D Rating[7]		N/A
New	Cooling Tower 8					0.7	lb/10^6 gal cooling water	AP-42[3]	EF D Rating[7]		N/A
New	HU Cooling Tower[13]										
New Flares											
New	GOHT Flare: Pilot					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
New	GOHT Flare: Purge					0.14	lb/10^6 Btu	AP-42[5]	EF B Rating[7]		0.1400
New	South Flare: Pilot					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
New	South Flare: Purge					0.14	lb/10^6 Btu	AP-42[5]	EF B Rating[7]		0.1400
New	HU Flare: Pilot					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
Marine Loading											
Cont	Gasoline Loading	See EF Reference[4]		AP-42[4]	Source Specific[8]	10	mg/L	Design[6]	Guarantee[9]	N/A	N/A
Lakefront											
SD	FBI (99-01)	0.34	lb/unit feed	Source testing						N/A	
SD	FBI (02-04)	0.0025	lb/Mgal WW	Source testing						N/A	
SD	FBI (02-06)	0.0305	lb/ton waste fed to FBI	Source testing						N/A	

Emission Factor Source References

[1] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4, "Natural Gas Combustion," Table 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION; (July 1998).

[2] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 5, Section 5.1, "Petroleum Refining," Table 5.1-1. EMISSIONS FOR PETROLEUM REFINERIES; (July 1995).

[3] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 5, Section 5.1, "Petroleum Refining," Table 5.1-2 FUGITIVE EMISSION FACTORS FOR PETROLEUM REFINING; (July 1995).

[4] U.S.EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 5, Section 5.2, Transportation and Marketing of Petroleum Liquid, Equation (1) and Table 5.2-1. SATURATION FACTOR FOR CALCULATING PETROLEUM LIQUID LOADING LOSS; (January 1995). Emission factor calculated using saturation factor, true vapor pressure, molecular weight, and temperature. See Tables C.45-47 for more details.

[5] U.S. AP-42. EPA. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.5, Industrial Flares Table 13.5-1. EMISSION FACTORS FOR FLARE OPERATION; (September 1991).

[6] Based on design requirement.

Justification Reference

[7] The Volatile Organic Compound (VOC) emission factors from AP-42 are used in the refinery industry as a standard when site specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.

[8] Based on source specific vapor pressure, temperature, and molecular weight.

[9] Based on anticipated vendor guarantee to satisfy design requirement.

Emission Unit References

[10] Existing unit being shutdown within the CXHO project contemporaneous period.

[11] Existing unit being shutdown as part of CXHO project.

[12] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same VOC emission factors.

[13] The new hydrogen unit cooling tower will be operated separately from refinery operations. VOC emissions are only applicable to cooling towers serving petroleum refinery operations.

[14] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.11. Project Combustion Emissions

Process Heaters and Boilers						VOC				NOx				SO2				PM(Filterable)				PM10/PM2.5 (Filterable + Condensable)				CO				Pb				H2SO4 Mist		Hg				Be			
Code	Process Unit	Capacity/Usage				EF	Unit	lb/hr[3]	tpy	EF	Unit	lb/hr[3]	tpy	EF	Unit	EF	Unit	lb/hr[3]	tpy[2]	EF	Unit	lb/hr[3]	tpy	EF	Unit	EF	Unit	lb/hr[3]	tpy	EF	Unit	lb/hr[3]	tpy	lb/hr[3]	tpy	EF	Unit	lb/hr[3]	tpy	EF	Unit	lb/hr[3]	tpy
Crude and Coking																																											
11A PS																																											
Oth	H-1X	173.9	MMBtu/hr	1,523,264	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.1	0.166	lb/MMBtu	28.9	126.4	13.30	lb/MMscf	0.0111	lb/MMBtu	1.9	8.4	0.0019	lb/MMBtu	0.3	1.4	7.6	lb/MMscf	0.0075	lb/MMBtu	1.3	5.7	0.082	lb/MMBtu	14.3	62.7	4.90E-07	lb/MMBtu	8.5E-05	3.7E-04	0.09	0.39	1.80E-07	lb/MMBtu	3.1E-05	1.4E-04	1.18E-08	lb/MMBtu	2.0E-06	9.0E-06
Oth	H-2	32.3	MMBtu/hr	282,948	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.098	lb/MMBtu	3.2	13.9	13.30	lb/MMscf	0.0111	lb/MMBtu	0.4	1.6	0.0019	lb/MMBtu	0.1	0.3	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	1.1	0.082	lb/MMBtu	2.7	11.7	4.90E-07	lb/MMBtu	1.6E-05	6.9E-05	0.02	0.07	1.80E-07	lb/MMBtu	5.8E-06	2.5E-05	1.18E-08	lb/MMBtu	3.8E-07	1.7E-06
Oth	H-3	49.2	MMBtu/hr	430,992	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.098	lb/MMBtu	4.8	21.1	13.30	lb/MMscf	0.0111	lb/MMBtu	0.5	2.4	0.0019	lb/MMBtu	0.1	0.4	7.6	lb/MMscf	0.0075	lb/MMBtu	0.4	1.6	0.082	lb/MMBtu	4.1	17.7	4.90E-07	lb/MMBtu	2.4E-05	1.1E-04	0.02	0.11	1.80E-07	lb/MMBtu	8.9E-06	3.9E-05	1.18E-08	lb/MMBtu	5.8E-07	2.5E-06
11C PS																																											
Cont	H-200	182.8	MMBtu/hr	1,601,328	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.3	0.05	lb/MMBtu	9.1	40.0	13.30	lb/MMscf	0.0111	lb/MMBtu	2.0	8.9	0.0019	lb/MMBtu	0.3	1.5	7.6	lb/MMscf	0.0075	lb/MMBtu	1.4	6.0	0.082	lb/MMBtu	15.1	65.9	4.90E-07	lb/MMBtu	9.0E-05	3.9E-04	0.09	0.41	1.80E-07	lb/MMBtu	3.3E-05	1.4E-04	1.18E-08	lb/MMBtu	2.2E-06	9.4E-06
Oth	H-300	72.0	MMBtu/hr	630,720	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.137	lb/MMBtu	9.9	43.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.8	3.5	0.0019	lb/MMBtu	0.1	0.6	7.6	lb/MMscf	0.0075	lb/MMBtu	0.5	2.3	0.082	lb/MMBtu	5.9	26.0	4.90E-07	lb/MMBtu	3.5E-05	1.5E-04	0.04	0.16	1.80E-07	lb/MMBtu	1.3E-05	5.7E-05	1.18E-08	lb/MMBtu	8.5E-07	3.7E-06
Coker																																											
SD	H-101	0.0	MMBtu/hr	0	MMBtu/yr																																						
SD	H-102	0.0	MMBtu/hr	0	MMBtu/yr																																						
SD	H-103	0.0	MMBtu/hr	0	MMBtu/yr																																						
SD	H-104	0.0	MMBtu/hr	0	MMBtu/yr																																						
New Coker (#2 Coker)																																											
New	H-201	208.0	MMBtu/hr	1,822,080	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.9	0.02	lb/MMBtu	4.2	18.2	13.30	lb/MMscf	0.0111	lb/MMBtu	2.3	10.1	0.0019	lb/MMBtu	0.5	2.3	7.6	lb/MMscf	0.0075	lb/MMBtu	1.7	7.4	0.019	lb/MMBtu	4.0	17.3	4.90E-07	lb/MMBtu	1.0E-04	4.5E-04	0.11	0.46	1.80E-07	lb/MMBtu	3.7E-05	1.6E-04	1.18E-08	lb/MMBtu	2.4E-06	1.1E-05
New	H-202	208.0	MMBtu/hr	1,822,080	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.9	0.02	lb/MMBtu	4.2	18.2	13.30	lb/MMscf	0.0111	lb/MMBtu	2.3	10.1	0.0019	lb/MMBtu	0.5	2.3	7.6	lb/MMscf	0.0075	lb/MMBtu	1.7	7.4	0.019	lb/MMBtu	4.0	17.3	4.90E-07	lb/MMBtu	1.0E-04	4.5E-04	0.11	0.46	1.80E-07	lb/MMBtu	3.7E-05	1.6E-04	1.18E-08	lb/MMBtu	2.4E-06	1.1E-05
New	H-203	208.0	MMBtu/hr	1,822,080	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.9	0.02	lb/MMBtu	4.2	18.2	13.30	lb/MMscf	0.0111	lb/MMBtu	2.3	10.1	0.0019	lb/MMBtu	0.5	2.3	7.6	lb/MMscf	0.0075	lb/MMBtu	1.7	7.4	0.019	lb/MMBtu	4.0	17.3	4.90E-07	lb/MMBtu	1.0E-04	4.5E-04	0.11	0.46	1.80E-07	lb/MMBtu	3.7E-05	1.6E-04	1.18E-08	lb/MMBtu	2.4E-06	1.1E-05
12PS																																											
SD	H-1AN	0.0	MMBtu/hr	0	MMBtu/yr																																						
SD	H-1AS	0.0	MMBtu/hr	0	MMBtu/yr																																						
SD	H-1B	0.0	MMBtu/hr	0	MMBtu/yr																																						
SD	H-1CN	0.0	MMBtu/hr	0	MMBtu/yr																																						
SD	H-1CX	0.0	MMBtu/hr	0	MMBtu/yr																																						
SD	H-2	0.0	MMBtu/hr	0	MMBtu/yr																																						
New	H-101A	355.0	MMBtu/hr	3,109,800	MMBtu/yr	0.0054	lb/MMBtu	1.9	8.4	0.05	lb/MMBtu	17.8	77.7	13.30	lb/MMscf	0.0111	lb/MMBtu	3.9	17.2	0.0019	lb/MMBtu	0.7	2.9	7.6	lb/MMscf	0.0075	lb/MMBtu	2.6	11.6	0.019	lb/MMBtu	6.7	29.5	4.90E-07	lb/MMBtu	1.7E-04	7.6E-04	0.18	0.79	1.80E-07	lb/MMBtu	6.4E-05	2.8E-04	1.18E-08	lb/MMBtu	4.2E-06	1.8E-05
New	H-102	331.0	MMBtu/hr	2,899,560	MMBtu/yr	0.0054	lb/MMBtu	1.8	7.8	0.05	lb/MMBtu	16.6	72.5	13.30	lb/MMscf	0.0111	lb/MMBtu	3.7	16.0	0.0019	lb/MMBtu	0.6	2.7	7.6	lb/MMscf	0.0075	lb/MMBtu	2.5	10.8	0.019	lb/MMBtu	6.3	27.5	4.90E-07	lb/MMBtu	1.6E-04	7.1E-04	0.17	0.74	1.80E-07	lb/MMBtu	6.0E-05	2.6E-04	1.18E-08	lb/MMBtu	3.9E-06	1.7E-05
New	H-101B	355.0	MMBtu/hr	3,109,800	MMBtu/yr	0.0054	lb/MMBtu	1.9	8.4	0.05	lb/MMBtu	17.8	77.7	13.30	lb/MMscf	0.0111	lb/MMBtu	3.9	17.2	0.0019	lb/MMBtu	0.7	2.9	7.6	lb/MMscf	0.0075	lb/MMBtu	2.6	11.6	0.019	lb/MMBtu	6.7	29.5	4.90E-07	lb/MMBtu	1.7E-04	7.6E-04	0.18	0.79	1.80E-07	lb/MMBtu	6.4E-05	2.8E-04	1.18E-08	lb/MMBtu	4.2E-06	1.8E-05
Hydroprocessing																																											
3UF																																											
SD	H-1	0.0	MMBtu/hr	0	MMBtu/yr																																						
SD	H-2	0.0	MMBtu/hr	0	MMBtu/yr																																						
SD	F-7	0.0	MMBtu/hr	0	MMBtu/yr																																						
4UF																																											
Oth	F-1	29.6	MMBtu/hr	259,296	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.098	lb/MMBtu	2.9	12.7	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.4	0.0019	lb/MMBtu	0.1	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	1.0	0.082	lb/MMBtu	2.4	10.7	4.90E-07	lb/MMBtu	1.5E-05	6.4E-05	0.02	0.07	1.80E-07	lb/MMBtu	5.3E-06	2.3E-05	1.18E-08	lb/MMBtu	3.5E-07	1.5E-06
Oth	F-8A	142.3	MMBtu/hr	1,246,548	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.4	0.275	lb/MMBtu	39.1	171.1	13.30	lb/MMscf	0.0111	lb/MMBtu	1.6	6.9	0.0019	lb/MMBtu	0.3	1.2	7.6	lb/MMscf	0.0075	lb/MMBtu	1.1	4.6	0.082	lb/MMBtu	11.7	51.3	4.90E-07	lb/MMBtu	7.0E-05	3.1E-04	0.07	0.32	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.3E-06
Oth	F-8B	142.3	MMBtu/hr	1,246,548	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.4	0.275	lb/MMBtu	39.1	171.1	13.30	lb/MMscf	0.0111	lb/MMBtu	1.6	6.9	0.0019	lb/MMBtu	0.3	1.2	7.6	lb/MMscf	0.0075	lb/MMBtu	1.1	4.6	0.082	lb/MMBtu	11.7	51.3	4.90E-07	lb/MMBtu	7.0E-05	3.1E-04	0.07	0.32	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.3E-06
Oth	F-2	169.9	MMBtu/hr	1,488,324	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.186	lb/MMBtu	31.6	138.6	13.30	lb/MMscf	0.0111	lb/MMBtu	1.9	8.2	0.0019	lb/MMBtu	0.3	1.4	7.6	lb/MMscf	0.0075	lb/MMBtu	1.3	5.5	0.082	lb/MMBtu	14.0	61.3	4.90E-07	lb/MMBtu	8.3E-05	3.6E-04	0.09	0.38	1.80E-07	lb/MMBtu	3.1E-05	1.3E-04	1.18E-08	lb/MMBtu	2.0E-06	8.8E-06
Oth	F-3	180.0	MMBtu/hr	1,576,800	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.3	0.275	lb/MMBtu	49.4	216.4	13.30	lb/MMscf	0.0111	lb/MMBtu	2.0	8.7	0.0019	lb/MMBtu	0.3	1.5	7.6	lb/MMscf	0.0075	lb/MMBtu	1.3	5.9	0.082	lb/MMBtu	14.8	64.9	4.90E-07	lb/MMBtu	8.8E-05	3.9E-04	0.09	0.40	1.80E-07	lb/MMBtu	3.2E-05	1.4E-04	1.18E-08	lb/MMBtu	2.1E-06	9.3E-06
Oth	F-4	96.8	MMBtu/hr	847,968	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.3	0.275	lb/MMBtu	26.6	116.4	13.30	lb/MMscf	0.0111	lb/MMBtu	1.1	4.7	0.0019	lb/MMBtu	0.2	0.8	7.6	lb/MMscf	0.0075	lb/MMBtu	0.7	3.2	0.082	lb/MMBtu	8.0	34.9	4.90E-07	lb/MMBtu	4.7E-05	2.1E-04	0.05	0.22	1.80E-07	lb/MMBtu	1.7E-05	7.6E-05	1.18E-08	lb/MMBtu	1.1E-06	5.0E-06
Oth	F-5	48.8	MMBtu/hr	427,488	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.098	lb/MMBtu	4.8	21.0	13.30	lb/MMscf	0.0111	lb/MMBtu	0.5	2.4	0.0019	lb/MMBtu	0.1	0.4	7.6	lb/MMscf	0.0075	lb/MMBtu	0.4	1.6	0.082	lb/MMBtu	4.0	17.6	4.90E-07	lb/MMBtu	2.4E-05	1.0E-04	0.02	0.11	1.80E-07	lb/MMBtu	8.8E-06	3.8E-05	1.18E-08	lb/MMBtu	5.7E-07	2.5E-06
Oth	F-6	21.7	MMBtu/hr	190,092	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.098	lb/MMBtu	2.1	9.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.2	1.1	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	1.8	7.8	4.90E-07	lb/MMBtu	1.1E-05	4.7E-05	0.01	0.05	1.80E-07	lb/MMBtu	3.9E-06	1.7E-05	1.18E-08	lb/MMBtu	2.6E-07	1.1E-06
Oth	F-7	36.2	MMBtu/hr	317,112	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.098	lb/MMBtu	3.5	15.5	13.30	lb/MMscf	0.0111	lb/MMBtu	0.4	1.8	0.0019	lb/MMBtu	0.1	0.3	7.6	lb/MMscf	0.0075	lb/MMBtu	0.3	1.2	0.082	lb/MMBtu	3.0	13.1	4.90E-07	lb/MMBtu	1.8E-05	7.8E-05	0.02	0.08	1.80E-07	lb/MMBtu	6.5E-06	2.9E-05	1.18E-08	lb/MMBtu	4.3E-07	1.9E-06
ARU																																											
Oth	F-200A	144.4	MMBtu/hr	1,264,944	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.4	0.275	lb/MMBtu	39.6	173.6	13.30	lb/MMscf	0.0111	lb/MMBtu	1.6	7.0	0.0019	lb/MMBtu	0.3	1.2	7.6	lb/MMscf	0.0075	lb/MMBtu	1.1	4.7	0.082	lb/MMBtu	11.9	52.1	4.90E-07	lb/MMBtu	7.1E-05	3.1E-04	0.07	0.32	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.4E-06
Oth	F-200B	144.4	MMBtu/hr	1,264,944	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.4	0.275	lb/MMBtu	39.6	173.6	13.30	lb/MMscf	0.0111	lb/MMBtu	1.6	7.0	0.0019	lb/MMBtu	0.3	1.2	7.6	lb/MMscf	0.0075	lb/MMBtu	1.1	4.7	0.082	lb/MMBtu	11.9	52.1	4.90E-07	lb/MMBtu	7.1E-05	3.1E-04	0.07	0.32	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.4E-06
BOU																																											
Mod	F-401	23.0	MMBtu/hr	201,480	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.098	lb/MMBtu	2.3	9.9	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.1	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	1.9	8.3	4.90E-07	lb/MMBtu	1.1E-05	4.9E-05	0.01	0.05	1.80E-07	lb/MMBtu	4.1E-06	1.8E-05	1.18E-08	lb/MMBtu	2.7E-07	1.2E-06
CPHU																																											
Oth	F-801A	24.6	MMBtu/hr	215,496	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.049	lb/MMBtu	1.2	5.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	2.0	8.9	4.90E-07	lb/MMBtu	1.2E-05	5.3E-05	0.01	0.05	1.80E-07	lb/MMBtu	4.4E-06	1.9E-05	1.18E-08	lb/MMBtu	2.9E-07	1.3E-06
Oth	F-801B	24.6	MMBtu/hr	215,496	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.049	lb/MMBtu	1.2	5.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	2.0	8.9	4.90E-07	lb/MMBtu	1.2E-05	5.3E-05	0.01	0.05	1.80E-07	lb/MMBtu	4.4E-06	1.9E-05	1.18E-08	lb/MMBtu	2.9E-07	1.3E-06
Oth	F-801C	24.6	MMBtu/hr	215,496	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.036	lb/MMBtu	0.9	3.9	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.8	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	1.2E-05	5.3E-05	0.01	0.05	1.80E-07	lb/MMBtu	4.4E-06	1.9E-05	1.18E-08	lb/MMBtu	2.9E-07	1.3E-06
GOHT																																											
New	F-901A	47.0	MMBtu/hr	411,720	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.04	lb/MMBtu	1.9	8.2	13.30	lb/MMscf	0.0111	lb/MMBtu	0.5	2.3	0.0019	lb/MMBtu	0.1	0.4	7.6	lb/MMscf	0.0075	lb/MMBtu	0.4	1.5	0.02	lb/MMBtu	0.9	4.1	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.02	0.10	1.80E-07	lb/MMBtu	8.5E-06	3.7E-05	1.18E-08	lb/MMBtu	5.5E-07	2.4E-06
New	F-901B	47.0	MMBtu/hr	411,720	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.04	lb/MMBtu	1.9	8.2	13.30	lb/MMscf	0.0111	lb/MMBtu	0.5	2.3	0.0019	lb/MMBtu	0.1	0.4	7.6	lb/MMscf	0.0075	lb/MMBtu	0.4	1.5	0.02	lb/MMBtu	0.9	4.1	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.02	0.10	1.80E-07	lb/MMBtu	8.5E-06	3.7E-05	1.18E-08	lb/MMBtu	5.5E-07	2.4E-06
CRU																																											
Oth	F-101	23.8	MMBtu/hr	208,488	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.08	lb/MMBtu	1.9	8.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	2.0	8.6	4.90E-07	lb/MMBtu	1.2E-05	5.1E-05	0.01	0.05	1.80E-07	lb/MMBtu	4.3E-06	1.9E-05	1.18E-08	lb/MMBtu	2.8E-07	1.2E-06
Oth	F-102	23.8	MMBtu/hr	208,488	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.08	lb/MMBtu	1.9	8.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	2.0	8.6	4.90E-07	lb/MMBtu	1.2E-05	5.1E-05	0.01	0.05	1.80E-07	lb/MMBtu	4.3E-06	1.9E-05	1.18E-08	lb/MMBtu	2.8E-07	1.2E-06
DDU																																											
Oth	WB-301	70.8	MMBtu/hr	620,208	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.035	lb/MMBtu	2.4	10.7	13.30	lb/MMscf	0.0111	lb/MMBtu	0.8	3.4	0.0019	lb/MMBtu	0.1	0.6	7.6	lb/MMscf	0.0075	lb/MMBtu	0.5	2.3	0.04	lb/MMBtu	2.8	12.4	4.90E-07	lb/MMBtu	3.5E-05	1.5E-04	0.04	0.16	1.80E-07	lb/MMBtu	1.3E-05	5.6E-05	1.18E-08	lb/MMBtu	8.3E-07	3.6E-06
Oth	WB-302	55.8	MMBtu/hr	488,808	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.3	0.03	lb/MMBtu	1.7	7.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.6	2.7	0.0019	lb/MMBtu	0.1	0.5	7.6	lb/MMscf	0.0075	lb/MMBtu	0.4	1.8	0.04	lb/MMBtu	2.2	9.8	4.90E-07	lb/MMBtu	2.7E-05	1.2E-04	0.03	0.12	1.80E-07	lb/MMBtu	1.0E-05	4.4E-05	1.18E-08	lb/MMBtu	6.6E-07	2.9E-06
DHT																																											
New	B-601A	41.9	MMBtu/hr	367,044	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.04	lb/MMBtu	1.7	7.3	0.60	lb/MMscf	0.0006	lb/MMBtu	0.0	0.1	0.0019	lb/MMBtu	0.0	0.1	7.6	lb/MMscf	0.0075	lb/MMBtu	0.3	1.4	0.04	lb/MMBtu	1.7	7.3	4.90E-07	lb/MMBtu	2.1E-05	9.0E-05	0.00	0.00	1.80E-07	lb/MMBtu	7.5E-06	3.3E-05	1.18E-08	lb/MMBtu	4.9E-07	2.2E-06
ISOM																																											
Mod	H-1	153.2	MMBtu/hr	1,342,032	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.6	0.275	lb/MMBtu	42.1	184.2	13.30	lb/MMscf	0.0111	lb/MMBtu	1.7	7.4	0.0019	lb/MMBtu	0.3	1.2	7.6	lb/MMscf	0.0075	lb/MMBtu	1.1	5.0	0.082	lb/MMBtu	12.6	55.3	4.90E-07	lb/MMBtu	7.5E-05	3.3E-04	0.08	0.34	1.80E-07	lb/MMBtu	2.8E-05	1.2E-04	1.18E-08	lb/MMBtu	1.8E-06	7.9E-06
HU																																											
Oth	B-501	320.7	MMBtu/hr	2,809,332	MMBtu/yr	0.0054	lb/MMBtu	1.7	7.6	0.068	lb/MMBtu	21.6	94.8	13.30	lb/MMscf	0.0111	lb/MMBtu	3.5	15.5	0.0019	lb/MMBtu	0.6	2.6	7.6	lb/MMscf	0.0075	lb/MMBtu	2.4	10.5	0.02	lb/MMBtu	6.4	28.1	4.90E-07	lb/MMBtu	1.6E-04	6.9E-04	0.16	0.71	1.80E-07	lb/MMBtu	5.8E-05	2.5E-04	1.18E-08	lb/MMBtu	3.8E-06	1.7E-05
New HU (3rd Party SMR)																																											
New	HU-1 (natural gas)	230.0	MMBtu/hr	2,014,800	MMBtu/yr	0.0034	lb/MMBtu	0.8	3.4	0.013	lb/MMBtu	3.0	13.1	0.60	lb/MMscf	0.0006	lb/MMBtu	0.1	0.6	0.0068	lb/MMBtu	1.6	6.9	0.0068	lb/MMBtu	0.0068	lb/MMBtu	1.6	6.9	0.015	lb/MMBtu	3.5	15.1	4.90E-07	lb/MMBtu	1.1E-04	4.9E-04	0.0	0.03	1.80E-07	lb/MMBtu	4.1E-05	1.8E-04	1.18E-08	lb/MMBtu	2.7E-06	1.2E-05
	HU-1 (PSA tail gas)	690.0	MMBtu/hr	6,044,400	MMBtu/yr	0.0034	lb/MMBtu	2.3	10.3	0.013	lb/MMBtu	9.0	39.3	0.00	lb/MMscf	0.0	lb/MMBtu	-	0.0	0.0068	lb/MMBtu	4.7	20.6	0.0068	lb/MMBtu	0.0068	lb/MMBtu	4.7	20.6	0.015	lb/MMBtu	10.4	45.3														
New	HU-2 (natural gas)	230.0	MMBtu/hr	2,014,800	MMBtu/yr	0.0034	lb/MMBtu	0.8	3.4	0.013	lb/MMBtu	3.0	13.1	0.60	lb/MMscf	0.0006	lb/MMBtu	0.1	0.6	0.0068	lb/MMBtu	1.6	6.9	0.0068	lb/MMBtu	0.0068	lb/MMBtu	1.6	6.9	0.015	lb/MMBtu	3.5	15.1	4.90E-07	lb/MMBtu	1.1E-04	4.9E-04	0.0	0.03	1.80E-07	lb/MMBtu	4.1E-05	1.8E-04	1.18E-08	lb/MMBtu	2.7E-06	1.2E-05
	HU-2 (PSA tail gas)	690.0	MMBtu/hr	6,044,400	MMBtu/yr	0.0034	lb/MMBtu	2.3	10.3	0.013	lb/MMBtu	9.0	39.3	0.00	lb/MMscf	0.0	lb/MMBtu	-	0.0	0.0068

Table C.12. 1999 Combustion Emissions

Process Heaters and Boilers

Code	Process Unit	Usage				VOC				NO_x				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[2]				CO				Pb				H_2SO_4 Mist		Hg				Be			
						EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
Crude and Coking																																											
11A PS																																											
Oth	H-1X	146.8	MMBtu/hr	1,286,310	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.1660	lb/MMBtu	24.4	106.8	0.0187	lb/MMBtu	2.7	12.0	0.0019	lb/MMBtu	0.3	1.2	0.0075	lb/MMBtu	1.1	4.8	0.082	lb/MMBtu	12.1	53.0	4.90E-07	lb/MMBtu	7.2E-05	3.2E-04	0.13	0.55	1.80E-07	lb/MMBtu	2.6E-05	1.2E-04	1.18E-08	lb/MMBtu	1.7E-06	7.6E-06
Oth	H-2	19.7	MMBtu/hr	172,977	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0980	lb/MMBtu	1.9	8.5	0.0187	lb/MMBtu	0.4	1.6	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	1.6	7.1	4.90E-07	lb/MMBtu	9.7E-06	4.2E-05	0.02	0.07	1.80E-07	lb/MMBtu	3.6E-06	1.6E-05	1.18E-08	lb/MMBtu	2.3E-07	1.0E-06
Oth	H-3	33.8	MMBtu/hr	296,101	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.3	14.5	0.0187	lb/MMBtu	0.6	2.8	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.3	1.1	0.082	lb/MMBtu	2.8	12.2	4.90E-07	lb/MMBtu	1.7E-05	7.3E-05	0.03	0.13	1.80E-07	lb/MMBtu	6.1E-06	2.7E-05	1.18E-08	lb/MMBtu	4.0E-07	1.7E-06
11C PS																																											
Cont	H-200	99.0	MMBtu/hr	867,329	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.3	0.2745	lb/MMBtu	27.2	119.0	0.0187	lb/MMBtu	1.9	8.1	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.7	3.2	0.082	lb/MMBtu	8.2	35.7	4.90E-07	lb/MMBtu	4.9E-05	2.1E-04	0.09	0.37	1.80E-07	lb/MMBtu	1.8E-05	7.8E-05	1.18E-08	lb/MMBtu	1.2E-06	5.1E-06
Oth	H-300	85.5	MMBtu/hr	749,162	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.0	0.1373	lb/MMBtu	11.7	51.4	0.0187	lb/MMBtu	1.6	7.0	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.6	2.8	0.082	lb/MMBtu	7.0	30.8	4.90E-07	lb/MMBtu	4.2E-05	1.8E-04	0.07	0.32	1.80E-07	lb/MMBtu	1.5E-05	6.7E-05	1.18E-08	lb/MMBtu	1.0E-06	4.4E-06
Coker																																											
SD	H-101	48.4	MMBtu/hr	423,821	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0980	lb/MMBtu	4.7	20.8	0.0187	lb/MMBtu	0.9	4.0	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	4.0	17.5	4.90E-07	lb/MMBtu	2.4E-05	1.0E-04	0.04	0.18	1.80E-07	lb/MMBtu	8.7E-06	3.8E-05	1.18E-08	lb/MMBtu	5.7E-07	2.5E-06
SD	H-102	52.6	MMBtu/hr	460,694	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.0980	lb/MMBtu	5.2	22.6	0.0187	lb/MMBtu	1.0	4.3	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	4.3	19.0	4.90E-07	lb/MMBtu	2.6E-05	1.1E-04	0.05	0.20	1.80E-07	lb/MMBtu	9.5E-06	4.1E-05	1.18E-08	lb/MMBtu	6.2E-07	2.7E-06
SD	H-103	52.6	MMBtu/hr	460,575	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.0980	lb/MMBtu	5.2	22.6	0.0187	lb/MMBtu	1.0	4.3	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	4.3	19.0	4.90E-07	lb/MMBtu	2.6E-05	1.1E-04	0.05	0.20	1.80E-07	lb/MMBtu	9.5E-06	4.1E-05	1.18E-08	lb/MMBtu	6.2E-07	2.7E-06
SD	H-104	52.6	MMBtu/hr	461,002	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.0980	lb/MMBtu	5.2	22.6	0.0187	lb/MMBtu	1.0	4.3	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	4.3	19.0	4.90E-07	lb/MMBtu	2.6E-05	1.1E-04	0.05	0.20	1.80E-07	lb/MMBtu	9.5E-06	4.1E-05	1.18E-08	lb/MMBtu	6.2E-07	2.7E-06
12PS																																											
SD	H-1AN	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.2745	lb/MMBtu	0.0	0.0	0.0187	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0075	lb/MMBtu	0.0	0.0	0.082	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.0E+00	0.0E+00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.18E-08	lb/MMBtu	0.0E+00	0.0E+00
SD	H-1AS	100.3	MMBtu/hr	878,915	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.4	0.2745	lb/MMBtu	27.5	120.6	0.0187	lb/MMBtu	1.9	8.2	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.7	3.3	0.082	lb/MMBtu	8.3	36.2	4.90E-07	lb/MMBtu	4.9E-05	2.2E-04	0.09	0.38	1.80E-07	lb/MMBtu	1.8E-05	7.9E-05	1.18E-08	lb/MMBtu	1.2E-06	5.2E-06
SD	H-1B	168.6	MMBtu/hr	1,477,301	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.2745	lb/MMBtu	46.3	202.8	0.0187	lb/MMBtu	3.2	13.8	0.0019	lb/MMBtu	0.3	1.4	0.0075	lb/MMBtu	1.3	5.5	0.082	lb/MMBtu	13.9	60.8	4.90E-07	lb/MMBtu	8.3E-05	3.6E-04	0.14	0.63	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.18E-08	lb/MMBtu	2.0E-06	8.7E-06
SD	H-2	97.6	MMBtu/hr	855,243	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.3	0.0360	lb/MMBtu	3.5	15.4	0.0187	lb/MMBtu	1.8	8.0	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.7	3.2	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	4.8E-05	2.1E-04	0.08	0.37	1.80E-07	lb/MMBtu	1.8E-05	7.7E-05	1.18E-08	lb/MMBtu	1.1E-06	5.0E-06
SD	H-1CN	34.8	MMBtu/hr	304,411	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.4	14.9	0.0187	lb/MMBtu	0.7	2.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.9	12.5	4.90E-07	lb/MMBtu	1.7E-05	7.5E-05	0.03	0.13	1.80E-07	lb/MMBtu	6.3E-06	2.7E-05	1.18E-08	lb/MMBtu	4.1E-07	1.8E-06
SD	H-1CX	197.8	MMBtu/hr	1,733,057	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.7	0.0990	lb/MMBtu	19.6	85.8	0.0187	lb/MMBtu	3.7	16.2	0.0019	lb/MMBtu	0.4	1.6	0.0040	lb/MMBtu	0.8	3.5	0.082	lb/MMBtu	16.3	71.4	4.90E-07	lb/MMBtu	9.7E-05	4.2E-04	0.17	0.74	1.80E-07	lb/MMBtu	3.6E-05	1.6E-04	1.18E-08	lb/MMBtu	2.3E-06	1.0E-05
Hydroprocessing																																											
3UF																																											
SD	H-1	166.9	MMBtu/hr	1,461,875	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.9	0.2745	lb/MMBtu	45.8	200.6	0.0050	lb/MMBtu	0.8	3.6	0.0019	lb/MMBtu	0.3	1.4	0.0040	lb/MMBtu	0.7	2.9	0.082	lb/MMBtu	13.7	60.2	4.90E-07	lb/MMBtu	8.2E-05	3.6E-04	0.04	0.17	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.18E-08	lb/MMBtu	2.0E-06	8.6E-06
SD	H-2	146.7	MMBtu/hr	1,285,206	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.2745	lb/MMBtu	40.3	176.4	0.0050	lb/MMBtu	0.7	3.2	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.6	0.082	lb/MMBtu	12.1	52.9	4.90E-07	lb/MMBtu	7.2E-05	3.2E-04	0.03	0.15	1.80E-07	lb/MMBtu	2.6E-05	1.2E-04	1.18E-08	lb/MMBtu	1.7E-06	7.6E-06
SD	F-7	19.3	MMBtu/hr	168,876	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0980	lb/MMBtu	1.9	8.3	0.0050	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.6	7.0	4.90E-07	lb/MMBtu	9.5E-06	4.1E-05	0.00	0.02	1.80E-07	lb/MMBtu	3.5E-06	1.5E-05	1.18E-08	lb/MMBtu	2.3E-07	9.9E-07
4UF																																											
Oth	F-1	47.0	MMBtu/hr	411,924	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0980	lb/MMBtu	4.6	20.2	0.0054	lb/MMBtu	0.3	1.1	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.9	17.0	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.01	0.05	1.80E-07	lb/MMBtu	8.5E-06	3.7E-05	1.18E-08	lb/MMBtu	5.5E-07	2.4E-06
Oth	F-8A	122.4	MMBtu/hr	1,072,493	MMBtu/yr	0.0054	lb/MMBtu	0.7	2.9	0.2745	lb/MMBtu	33.6	147.2	0.0054	lb/MMBtu	0.7	2.9	0.0019	lb/MMBtu	0.2	1.0	0.0040	lb/MMBtu	0.5	2.1	0.082	lb/MMBtu	10.1	44.2	4.90E-07	lb/MMBtu	6.0E-05	2.6E-04	0.03	0.13	1.80E-07	lb/MMBtu	2.2E-05	9.7E-05	1.18E-08	lb/MMBtu	1.4E-06	6.3E-06
Oth	F-8B	116.0	MMBtu/hr	1,016,141	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.7	0.2745	lb/MMBtu	31.8	139.5	0.0054	lb/MMBtu	0.6	2.8	0.0019	lb/MMBtu	0.2	0.9	0.0040	lb/MMBtu	0.5	2.0	0.082	lb/MMBtu	9.6	41.8	4.90E-07	lb/MMBtu	5.7E-05	2.5E-04	0.03	0.13	1.80E-07	lb/MMBtu	2.1E-05	9.1E-05	1.18E-08	lb/MMBtu	1.4E-06	6.0E-06
Oth	F-2	267.5	MMBtu/hr	2,343,419	MMBtu/yr	0.0054	lb/MMBtu	1.4	6.3	0.1863	lb/MMBtu	49.8	218.3	0.0054	lb/MMBtu	1.5	6.4	0.0019	lb/MMBtu	0.5	2.2	0.0040	lb/MMBtu	1.1	4.6	0.082	lb/MMBtu	22.0	96.5	4.90E-07	lb/MMBtu	1.3E-04	5.7E-04	0.07	0.29	1.80E-07	lb/MMBtu	4.8E-05	2.1E-04	1.18E-08	lb/MMBtu	3.1E-06	1.4E-05
Oth	F-3	221.9	MMBtu/hr	1,944,248	MMBtu/yr	0.0054	lb/MMBtu	1.2	5.2	0.2745	lb/MMBtu	60.9	266.9	0.0054	lb/MMBtu	1.2	5.3	0.0019	lb/MMBtu	0.4	1.8	0.0040	lb/MMBtu	0.9	3.9	0.082	lb/MMBtu	18.3	80.1	4.90E-07	lb/MMBtu	1.1E-04	4.8E-04	0.06	0.24	1.80E-07	lb/MMBtu	4.0E-05	1.7E-04	1.18E-08	lb/MMBtu	2.6E-06	1.1E-05
Oth	F-4	141.7	MMBtu/hr	1,241,323	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.3	0.2745	lb/MMBtu	38.9	170.4	0.0054	lb/MMBtu	0.8	3.4	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.5	0.082	lb/MMBtu	11.7	51.1	4.90E-07	lb/MMBtu	6.9E-05	3.0E-04	0.04	0.15	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.3E-06
Oth	F-5	45.2	MMBtu/hr	396,291	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.1	0.0980	lb/MMBtu	4.4	19.4	0.0054	lb/MMBtu	0.2	1.1	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.7	16.3	4.90E-07	lb/MMBtu	2.2E-05	9.7E-05	0.01	0.05	1.80E-07	lb/MMBtu	8.1E-06	3.6E-05	1.18E-08	lb/MMBtu	5.3E-07	2.3E-06
Oth	F-6	47.1	MMBtu/hr	412,712	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0980	lb/MMBtu	4.6	20.2	0.0054	lb/MMBtu	0.3	1.1	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.9	17.0	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.01	0.05	1.80E-07	lb/MMBtu	8.5E-06	3.7E-05	1.18E-08	lb/MMBtu	5.5E-07	2.4E-06
Oth	F-7	32.7	MMBtu/hr	286,821	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.2	14.1	0.0054	lb/MMBtu	0.2	0.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.7	11.8	4.90E-07	lb/MMBtu	1.6E-05	7.0E-05	0.01	0.04	1.80E-07	lb/MMBtu	5.9E-06	2.6E-05	1.18E-08	lb/MMBtu	3.9E-07	1.7E-06
ARU																																											
Oth	F-200A	199.2	MMBtu/hr	1,744,854	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.7	0.2745	lb/MMBtu	54.7	239.5	0.0187	lb/MMBtu	3.7	16.3	0.0019	lb/MMBtu	0.4	1.6	0.0040	lb/MMBtu	0.8	3.5	0.082	lb/MMBtu	16.4	71.8	4.90E-07	lb/MMBtu	9.8E-05	4.3E-04	0.17	0.75	1.80E-07	lb/MMBtu	3.6E-05	1.6E-04	1.18E-08	lb/MMBtu	2.3E-06	1.0E-05
Oth	F-200B	210.9	MMBtu/hr	1,847,296	MMBtu/yr	0.0054	lb/MMBtu	1.1	5.0	0.2745	lb/MMBtu	57.9	253.6	0.0187	lb/MMBtu	3.9	17.3	0.0019	lb/MMBtu	0.4	1.7	0.0040	lb/MMBtu	0.8	3.7	0.082	lb/MMBtu	17.4	76.1	4.90E-07	lb/MMBtu	1.0E-04	4.5E-04	0.18	0.79	1.80E-07	lb/MMBtu	3.8E-05	1.7E-04	1.18E-08	lb/MMBtu	2.5E-06	1.1E-05
BOU																																											
Mod	F-401	13.7	MMBtu/hr	119,952	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0980	lb/MMBtu	1.3	5.9	0.0054	lb/MMBtu	0.1	0.3	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.2	0.082	lb/MMBtu	1.1	4.9	4.90E-07	lb/MMBtu	6.7E-06	2.9E-05	0.00	0.01	1.80E-07	lb/MMBtu	2.5E-06	1.1E-05	1.18E-08	lb/MMBtu	1.6E-07	7.1E-07
CFHU																																											
Oth	F-801A	12.2	MMBtu/hr	107,139	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0490	lb/MMBtu	0.6	2.6	0.0049	lb/MMBtu	0.1	0.3	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	1.0	4.4	4.90E-07	lb/MMBtu	6.0E-06	2.6E-05	0.00	0.01	1.80E-07	lb/MMBtu	2.2E-06	9.6E-06	1.18E-08	lb/MMBtu	1.4E-07	6.3E-07
Oth	F-801B	12.2	MMBtu/hr	107,139	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0490	lb/MMBtu	0.6	2.6	0.0049	lb/MMBtu	0.1	0.3	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	1.0	4.4	4.90E-07	lb/MMBtu	6.0E-06	2.6E-05	0.00	0.01	1.80E-07	lb/MMBtu	2.2E-06	9.6E-06	1.18E-08	lb/MMBtu	1.4E-07	6.3E-07
Oth	F-801C	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.0360	lb/MMBtu	0.0	0.0	0.0049	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0040	lb/MMBtu	0.0	0.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.0E+00	0.0E+00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.18E-08	lb/MMBtu	0.0E+00	0.0E+00
CRU																																											
Oth	F-101	41.3	MMBtu/hr	361,928	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0800	lb/MMBtu	3.3	14.5	0.0050	lb/MMBtu	0.2	0.9	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.4	14.9	4.90E-07	lb/MMBtu	2.0E-05	8.9E-05	0.01	0.04	1.80E-07	lb/MMBtu	7.4E-06	3.3E-05	1.18E-08	lb/MMBtu	4.9E-07	2.1E-06
Oth	F-102	19.3	MMBtu/hr	169,317	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0800	lb/MMBtu	1.5	6.8	0.0050	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.6	7.0	4.90E-07	lb/MMBtu	9.5E-06	4.1E-05	0.00	0.02	1.80E-07	lb/MMBtu	3.5E-06	1.5E-05	1.18E-08	lb/MMBtu	2.3E-07	1.0E-06
DOU																																											
Oth	WB-301	40.2	MMBtu/hr	352,461	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0346	lb/MMBtu	1.4	6.1	0.0187	lb/MMBtu	0.8	3.3	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.040	lb/MMBtu	1.6	7.0	4.90E-07	lb/MMBtu	2.0E-05	8.6E-05	0.03	0.15	1.80E-07	lb/MMBtu	7.2E-06	3.2E-05	1.18E-08	lb/MMBtu	4.7E-07	2.1E-06
Oth	WB-302	66.5	MMBtu/hr	582,883	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.6	0.0300	lb/MMBtu	2.0	8.7	0.0187	lb/MMBtu	1.2	5.5	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.2	1.1	0.040	lb/MMBtu	2.7	11.7	4.90E-07	lb/MMBtu	3.3E-05	1.4E-04	0.06	0.25	1.80E-07	lb/MMBtu	1.2E-05	5.2E-05	1.18E-08	lb/MMBtu	7.8E-07	3.4E-06
ISOM																																											
Mod	H-1	208.3	MMBtu/hr	1,824,954	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.9	0.2745	lb/MMBtu	57.2	250.5	0.0187	lb/MMBtu	3.9	17.1	0.0019	lb/MMBtu	0.4	1.7	0.0040	lb/MMBtu	0.7	3.1	0.082	lb/MMBtu	17.2	75.1	4.90E-07	lb/MMBtu	1.0E-04	4.5E-04	0.18	0.78	1.80E-07	lb/MMBtu	3.7E-05	1.6E-04	1.18E-08	lb/MMBtu	2.5E-06	1.1E-05
HU																																											
Oth	B-501	164.6	MMBtu/hr	1,441,540	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.9	0.0675	lb/MMBtu	11.1	48.7	0.0618	lb/MMBtu	10.2	44.6	0.0019	lb/MMBtu	0.3	1.3	0.0075	lb/MMBtu	1.2	5.4	0.02	lb/MMBtu	3.3	14.4	4.90E-07	lb/MMBtu	8.1E-05	3.5E-04	0.47	2.04	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.18E-08	lb/MMBtu	1.9E-06	8.5E-06
Utilities																																											
1SPS																																											
SD	Boiler 3	43.5	MMBtu/hr	381,467	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.1570	lb/MMBtu	6.8	29.9	0.0187	lb/MMBtu	0.8	3.6	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.3	1.4	0.049	lb/MMBtu	2.1	9.3	4.90E-07	lb/MMBtu	2.1E-05	9.3E-05	0.04	0.16	1.80E-07	lb/MMBtu	7.8E-06	3.4E-05	1.18E-08	lb/MMBtu	5.1E-07	2.2E-06
SD	Boiler 4	61.7	MMBtu/hr	540,317	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.5	0.1570	lb/MMBtu	9.7	42.4	0.0187	lb/MMBtu	1.2	5.1	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.5	2.0	0.049	lb/MMBtu	3.0	13.2	4.90E-07	lb/MMBtu	3.0E-05	1.3E-04	0.05	0.23	1.80E-07	lb/MMBtu	1.1E-05	4.9E-05	1.18E-08	lb/MMBtu	7.3E-07	3.2E-06
SD	Boiler 5	40.2	MMBtu/hr	351,888	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0930	lb/MMBtu	3.7	16.4	0.0187	lb/MMBtu	0.8	3.3	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.3	1.3	0.248	lb/MMBtu	10.0	43.6	4.90E-07	lb/MMBtu	2.0E-05	8.6E-05	0.03	0.15	1.80E-07	lb/MMBtu	7.2E-06	3.2E-05	1.18E-08	lb/MMBtu	4.7E-07	2.1E-06
SD	Boiler 6	26.4	MMBtu/hr	231,476	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0930	lb/MMBtu	2.5	10.8	0.0187	lb/MMBtu	0.5	2.2	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.2	0.9	0.248	lb/MMBtu	6.6	28.7	4.90E-07	lb/MMBtu	1.3E-05	5.7E-05	0.02	0.10	1.80E-07	lb/MMBtu	4.8E-06	2.1E-05	1.18E-08	lb/MMBtu	3.1E-07	1.4E-06
SD	Boiler 7	51.7	MMBtu/hr	452,903	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.0930	lb/MMBtu	4.8	21.0	0.0187	lb/MMBtu	1.0	4.2	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.4	1.7	0.248	lb/MMBtu	12.8	56.1	4.90E-07	lb/MMBtu	2.5E-05	1.1E-04	0.04	0.19	1.80E-07	lb/MMBtu	9.3E-06	4.1E-05	1.18E-08	lb/MMBtu	6.1E-07	2.7E-06
Lakefront																																											
SD	FBI	39,365	tons feed			0.34	lb/unit feed	1.5	6.7	0.14	lb/unit feed	0.6	2.8	0.13	lb/unit feed	0.6	2.6	0.184	lb/unit feed	0.8	3.6	0.184	l

Table C.13. 2000 Combustion Emissions

Code	Process Unit	Usage				VOC EF	VOC Unit	VOC lb/hr[1]	VOC tpy	NO_x EF	NO_x Unit	NO_x lb/hr[1]	NO_x tpy	SO_2 EF	SO_2 Unit	SO_2 lb/hr[1]	SO_2 tpy	PM (Filterable) EF	PM (Filterable) Unit	PM (Filterable) lb/hr[1]	PM (Filterable) tpy	$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[2] EF	$PM_{10}/PM_{2.5}$ Unit	$PM_{10}/PM_{2.5}$ lb/hr[1]	$PM_{10}/PM_{2.5}$ tpy	CO EF	CO Unit	CO lb/hr[1]	CO tpy	Pb EF	Pb Unit	Pb lb/hr[1]	Pb tpy	H_2SO_4 Mist lb/hr[1]	H_2SO_4 Mist tpy	Hg EF	Hg Unit	Hg lb/hr[1]	Hg tpy	Be EF	Be Unit	Be lb/hr[1]	Be tpy
Process Heaters and Boilers																																											
Crude and Coking																																											
11A PS																																											
Oth	H-1X	130.2	MMBtu/hr	1,140,204	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.1	0.1660	lb/MMBtu	21.6	94.6	0.0214	lb/MMBtu	2.8	12.2	0.0019	lb/MMBtu	0.2	1.1	0.0075	lb/MMBtu	1.0	4.2	0.082	lb/MMBtu	10.7	46.9	4.90E-07	lb/MMBtu	6.4E-05	2.8E-04	0.13	0.56	1.80E-07	lb/MMBtu	2.3E-05	1.0E-04	1.20E-05	lb/MMBtu	1.5E-06	6.7E-06
Oth	H-2	21.7	MMBtu/hr	189,885	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0980	lb/MMBtu	2.1	9.3	0.0214	lb/MMBtu	0.5	2.0	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	1.8	7.8	4.90E-07	lb/MMBtu	1.1E-05	4.7E-05	0.02	0.09	1.80E-07	lb/MMBtu	3.9E-06	1.7E-05	1.20E-05	lb/MMBtu	2.6E-07	1.1E-06
Oth	H-3	32.8	MMBtu/hr	287,244	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.2	14.1	0.0214	lb/MMBtu	0.7	3.1	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.2	1.1	0.082	lb/MMBtu	2.7	11.8	4.90E-07	lb/MMBtu	1.6E-05	7.0E-05	0.03	0.14	1.80E-07	lb/MMBtu	5.9E-06	2.6E-05	1.20E-05	lb/MMBtu	3.9E-07	1.7E-06
11C PS																																											
Cont	H-200	86.3	MMBtu/hr	756,300	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.0	0.2745	lb/MMBtu	23.7	103.8	0.0214	lb/MMBtu	1.8	8.1	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.6	2.8	0.082	lb/MMBtu	7.1	31.1	4.90E-07	lb/MMBtu	4.2E-05	1.9E-04	0.08	0.37	1.80E-07	lb/MMBtu	1.6E-05	6.8E-05	1.20E-05	lb/MMBtu	1.0E-06	4.4E-06
Oth	H-300	72.5	MMBtu/hr	635,479	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.1373	lb/MMBtu	10.0	43.6	0.0214	lb/MMBtu	1.5	6.8	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.5	2.4	0.082	lb/MMBtu	6.0	26.2	4.90E-07	lb/MMBtu	3.6E-05	1.6E-04	0.07	0.31	1.80E-07	lb/MMBtu	1.3E-05	5.7E-05	1.20E-05	lb/MMBtu	8.5E-07	3.7E-06
Coker																																											
SD	H-101	40.9	MMBtu/hr	358,143	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.0	17.6	0.0214	lb/MMBtu	0.9	3.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.4	14.7	4.90E-07	lb/MMBtu	2.0E-05	8.8E-05	0.04	0.18	1.80E-07	lb/MMBtu	7.4E-06	3.2E-05	1.20E-05	lb/MMBtu	4.8E-07	2.1E-06
SD	H-102	44.8	MMBtu/hr	392,147	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.1	0.0980	lb/MMBtu	4.4	19.2	0.0214	lb/MMBtu	1.0	4.2	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.7	16.1	4.90E-07	lb/MMBtu	2.2E-05	9.6E-05	0.04	0.19	1.80E-07	lb/MMBtu	8.1E-06	3.5E-05	1.20E-05	lb/MMBtu	5.3E-07	2.3E-06
SD	H-103	42.7	MMBtu/hr	374,401	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.2	18.4	0.0214	lb/MMBtu	0.9	4.0	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.5	15.4	4.90E-07	lb/MMBtu	2.1E-05	9.2E-05	0.04	0.18	1.80E-07	lb/MMBtu	7.7E-06	3.4E-05	1.20E-05	lb/MMBtu	5.0E-07	2.2E-06
SD	H-104	42.5	MMBtu/hr	372,259	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.2	18.2	0.0214	lb/MMBtu	0.9	4.0	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.5	15.3	4.90E-07	lb/MMBtu	2.1E-05	9.1E-05	0.04	0.18	1.80E-07	lb/MMBtu	7.6E-06	3.4E-05	1.20E-05	lb/MMBtu	5.0E-07	2.2E-06
12PS																																											
SD	H-1AN	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.2745	lb/MMBtu	0.0	0.0	0.0214	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0075	lb/MMBtu	0.0	0.0	0.082	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.00	0.00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.20E-05	lb/MMBtu	0.0E+00	0.0E+00
SD	H-1AS	95.8	MMBtu/hr	839,531	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.3	0.2745	lb/MMBtu	26.3	115.2	0.0214	lb/MMBtu	2.0	9.0	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.7	3.1	0.082	lb/MMBtu	7.9	34.6	4.90E-07	lb/MMBtu	4.7E-05	2.1E-04	0.09	0.41	1.80E-07	lb/MMBtu	1.7E-05	7.6E-05	1.20E-05	lb/MMBtu	1.1E-06	4.9E-06
SD	H-1B	168.5	MMBtu/hr	1,476,481	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.2745	lb/MMBtu	46.3	202.7	0.0214	lb/MMBtu	3.6	15.8	0.0019	lb/MMBtu	0.3	1.4	0.0075	lb/MMBtu	1.3	5.5	0.082	lb/MMBtu	13.9	60.8	4.90E-07	lb/MMBtu	8.3E-05	3.6E-04	0.17	0.72	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.20E-05	lb/MMBtu	2.0E-06	8.7E-06
SD	H-2	92.5	MMBtu/hr	810,314	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.2	0.0360	lb/MMBtu	3.3	14.6	0.0214	lb/MMBtu	2.0	8.7	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.7	3.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	4.5E-05	2.0E-04	0.09	0.40	1.80E-07	lb/MMBtu	1.7E-05	7.3E-05	1.20E-05	lb/MMBtu	1.1E-06	4.8E-06
SD	H-1CN	34.0	MMBtu/hr	298,064	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.3	14.6	0.0214	lb/MMBtu	0.7	3.2	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.8	12.3	4.90E-07	lb/MMBtu	1.7E-05	7.3E-05	0.03	0.15	1.80E-07	lb/MMBtu	6.1E-06	2.7E-05	1.20E-05	lb/MMBtu	4.0E-07	1.8E-06
SD	H-1CX	168.5	MMBtu/hr	1,476,360	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.0990	lb/MMBtu	16.7	73.1	0.0214	lb/MMBtu	3.6	15.8	0.0019	lb/MMBtu	0.3	1.4	0.0040	lb/MMBtu	0.7	3.0	0.082	lb/MMBtu	13.9	60.8	4.90E-07	lb/MMBtu	8.3E-05	3.6E-04	0.17	0.72	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.20E-05	lb/MMBtu	2.0E-06	8.7E-06
Hydroprocessing																																											
3UF																																											
SD	H-1	148.6	MMBtu/hr	1,301,376	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.2745	lb/MMBtu	40.8	178.6	0.0079	lb/MMBtu	1.2	5.1	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.6	0.082	lb/MMBtu	12.2	53.6	4.90E-07	lb/MMBtu	7.3E-05	3.2E-04	0.05	0.24	1.80E-07	lb/MMBtu	2.7E-05	1.2E-04	1.20E-05	lb/MMBtu	1.7E-06	7.7E-06
SD	H-2	141.3	MMBtu/hr	1,238,145	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.3	0.2745	lb/MMBtu	38.8	169.9	0.0079	lb/MMBtu	1.1	4.9	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.5	0.082	lb/MMBtu	11.6	51.0	4.90E-07	lb/MMBtu	6.9E-05	3.0E-04	0.05	0.22	1.80E-07	lb/MMBtu	2.5E-05	1.1E-04	1.20E-05	lb/MMBtu	1.7E-06	7.3E-06
SD	F-7	19.1	MMBtu/hr	167,265	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0980	lb/MMBtu	1.9	8.2	0.0079	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.6	6.9	4.90E-07	lb/MMBtu	9.4E-06	4.1E-05	0.01	0.03	1.80E-07	lb/MMBtu	3.4E-06	1.5E-05	1.20E-05	lb/MMBtu	2.2E-07	9.8E-07
4UF																																											
Oth	F-1	28.9	MMBtu/hr	253,233	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	2.8	12.4	0.0056	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.4	10.4	4.90E-07	lb/MMBtu	1.4E-05	6.2E-05	0.01	0.03	1.80E-07	lb/MMBtu	5.2E-06	2.3E-05	1.20E-05	lb/MMBtu	3.4E-07	1.5E-06
Oth	F-8A	74.7	MMBtu/hr	654,389	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.2745	lb/MMBtu	20.5	89.8	0.0056	lb/MMBtu	0.4	1.8	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.3	1.3	0.082	lb/MMBtu	6.2	26.9	4.90E-07	lb/MMBtu	3.7E-05	1.6E-04	0.02	0.08	1.80E-07	lb/MMBtu	1.3E-05	5.9E-05	1.20E-05	lb/MMBtu	8.8E-07	3.8E-06
Oth	F-8B	69.7	MMBtu/hr	610,848	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.6	0.2745	lb/MMBtu	19.1	83.8	0.0056	lb/MMBtu	0.4	1.7	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.3	1.2	0.082	lb/MMBtu	5.7	25.2	4.90E-07	lb/MMBtu	3.4E-05	1.5E-04	0.02	0.08	1.80E-07	lb/MMBtu	1.3E-05	5.5E-05	1.20E-05	lb/MMBtu	8.2E-07	3.6E-06
Oth	F-2	184.0	MMBtu/hr	1,611,778	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.3	0.1863	lb/MMBtu	34.3	150.1	0.0056	lb/MMBtu	1.0	4.5	0.0019	lb/MMBtu	0.3	1.5	0.0040	lb/MMBtu	0.7	3.2	0.082	lb/MMBtu	15.2	66.4	4.90E-07	lb/MMBtu	9.0E-05	4.0E-04	0.05	0.21	1.80E-07	lb/MMBtu	3.3E-05	1.5E-04	1.20E-05	lb/MMBtu	2.2E-06	9.5E-06
Oth	F-3	180.9	MMBtu/hr	1,584,466	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.3	0.2745	lb/MMBtu	49.7	217.5	0.0056	lb/MMBtu	1.0	4.5	0.0019	lb/MMBtu	0.3	1.5	0.0040	lb/MMBtu	0.7	3.2	0.082	lb/MMBtu	14.9	65.2	4.90E-07	lb/MMBtu	8.9E-05	3.9E-04	0.05	0.20	1.80E-07	lb/MMBtu	3.3E-05	1.4E-04	1.20E-05	lb/MMBtu	2.1E-06	9.3E-06
Oth	F-4	100.6	MMBtu/hr	881,291	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.4	0.2745	lb/MMBtu	27.6	121.0	0.0056	lb/MMBtu	0.6	2.5	0.0019	lb/MMBtu	0.2	0.8	0.0040	lb/MMBtu	0.4	1.8	0.082	lb/MMBtu	8.3	36.3	4.90E-07	lb/MMBtu	4.9E-05	2.2E-04	0.03	0.11	1.80E-07	lb/MMBtu	1.8E-05	7.9E-05	1.20E-05	lb/MMBtu	1.2E-06	5.2E-06
Oth	F-5	42.8	MMBtu/hr	374,869	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.2	18.4	0.0056	lb/MMBtu	0.2	1.1	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.5	15.4	4.90E-07	lb/MMBtu	2.1E-05	9.2E-05	0.01	0.05	1.80E-07	lb/MMBtu	7.7E-06	3.4E-05	1.20E-05	lb/MMBtu	5.0E-07	2.2E-06
Oth	F-6	33.1	MMBtu/hr	290,286	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.2	14.2	0.0056	lb/MMBtu	0.2	0.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.7	12.0	4.90E-07	lb/MMBtu	1.6E-05	7.1E-05	0.01	0.04	1.80E-07	lb/MMBtu	6.0E-06	2.6E-05	1.20E-05	lb/MMBtu	3.9E-07	1.7E-06
Oth	F-7	30.4	MMBtu/hr	266,092	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	3.0	13.0	0.0056	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.5	11.0	4.90E-07	lb/MMBtu	1.5E-05	6.5E-05	0.01	0.03	1.80E-07	lb/MMBtu	5.5E-06	2.4E-05	1.20E-05	lb/MMBtu	3.6E-07	1.6E-06
ARU																																											
Oth	F-200A	130.8	MMBtu/hr	1,146,143	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.1	0.2745	lb/MMBtu	35.9	157.3	0.0214	lb/MMBtu	2.8	12.2	0.0019	lb/MMBtu	0.2	1.1	0.0040	lb/MMBtu	0.5	2.3	0.082	lb/MMBtu	10.8	47.2	4.90E-07	lb/MMBtu	6.4E-05	2.8E-04	0.13	0.56	1.80E-07	lb/MMBtu	2.4E-05	1.0E-04	1.20E-05	lb/MMBtu	1.5E-06	6.7E-06
Oth	F-200B	129.2	MMBtu/hr	1,132,105	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.1	0.2745	lb/MMBtu	35.5	155.4	0.0214	lb/MMBtu	2.8	12.1	0.0019	lb/MMBtu	0.2	1.1	0.0040	lb/MMBtu	0.5	2.3	0.082	lb/MMBtu	10.6	46.6	4.90E-07	lb/MMBtu	6.3E-05	2.8E-04	0.13	0.55	1.80E-07	lb/MMBtu	2.3E-05	1.0E-04	1.20E-05	lb/MMBtu	1.5E-06	6.7E-06
BOU																																											
Mod	F-401	16.7	MMBtu/hr	146,186	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0980	lb/MMBtu	1.6	7.2	0.0056	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.4	6.0	4.90E-07	lb/MMBtu	8.2E-06	3.6E-05	0.00	0.02	1.80E-07	lb/MMBtu	3.0E-06	1.3E-05	1.20E-05	lb/MMBtu	2.0E-07	8.6E-07
CFHU																																											
Oth	F-801A	10.2	MMBtu/hr	89,468	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.2	0.0490	lb/MMBtu	0.5	2.2	0.0047	lb/MMBtu	0.0	0.2	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.8	3.7	4.90E-07	lb/MMBtu	5.0E-06	2.2E-05	0.00	0.01	1.80E-07	lb/MMBtu	1.8E-06	8.1E-06	1.20E-05	lb/MMBtu	1.2E-07	5.3E-07
Oth	F-801B	10.2	MMBtu/hr	89,468	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.2	0.0490	lb/MMBtu	0.5	2.2	0.0047	lb/MMBtu	0.0	0.2	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.8	3.7	4.90E-07	lb/MMBtu	5.0E-06	2.2E-05	0.00	0.01	1.80E-07	lb/MMBtu	1.8E-06	8.1E-06	1.20E-05	lb/MMBtu	1.2E-07	5.3E-07
Oth	F-801C	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.0360	lb/MMBtu	0.0	0.0	0.0047	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0040	lb/MMBtu	0.0	0.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.00	0.00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.20E-05	lb/MMBtu	0.0E+00	0.0E+00
CRU																																											
Oth	F-101	46.4	MMBtu/hr	406,589	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0800	lb/MMBtu	3.7	16.3	0.0079	lb/MMBtu	0.4	1.6	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.8	16.7	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.02	0.07	1.80E-07	lb/MMBtu	8.4E-06	3.7E-05	1.20E-05	lb/MMBtu	5.5E-07	2.4E-06
Oth	F-102	25.0	MMBtu/hr	219,187	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0800	lb/MMBtu	2.0	8.8	0.0079	lb/MMBtu	0.2	0.9	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.1	0.4	0.082	lb/MMBtu	2.1	9.0	4.90E-07	lb/MMBtu	1.2E-05	5.4E-05	0.01	0.04	1.80E-07	lb/MMBtu	4.5E-06	2.0E-05	1.20E-05	lb/MMBtu	2.9E-07	1.3E-06
DDU																																											
Oth	WB-301	35.7	MMBtu/hr	313,034	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0346	lb/MMBtu	1.2	5.4	0.0214	lb/MMBtu	0.8	3.3	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.040	lb/MMBtu	1.4	6.3	4.90E-07	lb/MMBtu	1.8E-05	7.7E-05	0.04	0.15	1.80E-07	lb/MMBtu	6.4E-06	2.8E-05	1.20E-05	lb/MMBtu	4.2E-07	1.8E-06
Oth	WB-302	57.3	MMBtu/hr	501,791	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.4	0.0300	lb/MMBtu	1.7	7.5	0.0214	lb/MMBtu	1.2	5.4	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.2	1.0	0.040	lb/MMBtu	2.3	10.0	4.90E-07	lb/MMBtu	2.8E-05	1.2E-04	0.06	0.25	1.80E-07	lb/MMBtu	1.0E-05	4.5E-05	1.20E-05	lb/MMBtu	6.7E-07	3.0E-06
ISOM																																											
Mod	H-1	152.1	MMBtu/hr	1,332,776	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.6	0.2745	lb/MMBtu	41.8	182.9	0.0214	lb/MMBtu	3.2	14.2	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.7	0.082	lb/MMBtu	12.5	54.9	4.90E-07	lb/MMBtu	7.5E-05	3.3E-04	0.15	0.65	1.80E-07	lb/MMBtu	2.7E-05	1.2E-04	1.20E-05	lb/MMBtu	1.8E-06	7.8E-06
HU																																											
Oth	B-501	193.5	MMBtu/hr	1,694,674	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.6	0.0675	lb/MMBtu	13.1	57.2	0.0717	lb/MMBtu	13.9	60.8	0.0019	lb/MMBtu	0.4	1.6	0.0075	lb/MMBtu	1.4	6.3	0.02	lb/MMBtu	3.9	16.9	4.90E-07	lb/MMBtu	9.5E-05	4.2E-04	0.64	2.79	1.80E-07	lb/MMBtu	3.5E-05	1.5E-04	1.20E-05	lb/MMBtu	2.3E-06	1.0E-05
Utilities																																											
1SPS																																											
SD	Boiler 3	22.6	MMBtu/hr	198,018	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.1570	lb/MMBtu	3.5	15.5	0.0214	lb/MMBtu	0.5	2.1	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.2	0.7	0.049	lb/MMBtu	1.1	4.9	4.90E-07	lb/MMBtu	1.1E-05	4.9E-05	0.02	0.10	1.80E-07	lb/MMBtu	4.1E-06	1.8E-05	1.20E-05	lb/MMBtu	2.7E-07	1.2E-06
SD	Boiler 4	35.7	MMBtu/hr	312,799	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.1570	lb/MMBtu	5.6	24.6	0.0214	lb/MMBtu	0.8	3.3	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.3	1.2	0.049	lb/MMBtu	1.7	7.7	4.90E-07	lb/MMBtu	1.8E-05	7.7E-05	0.04	0.15	1.80E-07	lb/MMBtu	6.4E-06	2.8E-05	1.20E-05	lb/MMBtu	4.2E-07	1.8E-06
SD	Boiler 5	20.3	MMBtu/hr	178,181	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0930	lb/MMBtu	1.9	8.3	0.0214	lb/MMBtu	0.4	1.9	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.2	0.7	0.248	lb/MMBtu	5.0	22.1	4.90E-07	lb/MMBtu	1.0E-05	4.4E-05	0.02	0.09	1.80E-07	lb/MMBtu	3.7E-06	1.6E-05	1.20E-05	lb/MMBtu	2.4E-07	1.0E-06
SD	Boiler 6	20.0	MMBtu/hr	175,392	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0930	lb/MMBtu	1.9	8.2	0.0214	lb/MMBtu	0.4	1.9	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.1	0.7	0.248	lb/MMBtu	5.0	21.7	4.90E-07	lb/MMBtu	9.9E-06	4.3E-05	0.02	0.09	1.80E-07	lb/MMBtu	3.6E-06	1.6E-05	1.20E-05	lb/MMBtu	2.4E-07	1.0E-06
SD	Boiler 7	74.6	MMBtu/hr	653,701	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.0930	lb/MMBtu	6.9	30.4	0.0214	lb/MMBtu	1.6	7.0	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.6	2.4	0.248	lb/MMBtu	18.5	81.1	4.90E-07	lb/MMBtu	3.7E-05	1.6E-04	0.07	0.32	1.80E-07	lb/MMBtu	1.3E-05	5.9E-05	1.20E-05	lb/MMBtu	8.8E-07	3.8E-06
Lakefront																							

Table C.14 2001 Combustion Emissions

Process Heaters and Boilers

Code	Process Unit	Usage				VOC EF	VOC Unit	VOC lb/hr[1]	VOC tpy	NO_x EF	NO_x Unit	NO_x lb/hr[1]	NO_x tpy	SO_2 EF	SO_2 Unit	SO_2 lb/hr[1]	SO_2 tpy	PM (Filterable) EF	PM (Filterable) Unit	PM (Filterable) lb/hr[1]	PM (Filterable) tpy	$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[2] EF	$PM_{10}/PM_{2.5}$ Unit	$PM_{10}/PM_{2.5}$ lb/hr[1]	$PM_{10}/PM_{2.5}$ tpy	CO EF	CO Unit	CO lb/hr[1]	CO tpy	Pb EF	Pb Unit	Pb lb/hr[1]	Pb tpy	H_2SO_4 Mist lb/hr[1]	H_2SO_4 Mist tpy	Hg EF	Hg Unit	Hg lb/hr[1]	Hg tpy	Be EF	Be Unit	Be lb/hr[1]	Be tpy
Crude and Coking																																											
11A PS																																											
Oth	H-1X	136.3	MMBtu/hr	1,193,746	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.2	0.1660	lb/MMBtu	22.6	99.1	0.0217	lb/MMBtu	3.0	12.9	0.0019	lb/MMBtu	0.3	1.1	0.0075	lb/MMBtu	0.0	4.4	0.082	lb/MMBtu	11.2	49.2	4.90E-07	lb/MMBtu	6.7E-05	2.9E-04	0.14	0.59	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	7.0E-06
Oth	H-2	32.7	MMBtu/hr	286,613	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.2	14.0	0.0217	lb/MMBtu	0.7	3.1	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.0	1.1	0.082	lb/MMBtu	2.7	11.8	4.90E-07	lb/MMBtu	1.6E-05	7.0E-05	0.03	0.14	1.80E-07	lb/MMBtu	0.0E+00	2.6E-05	1.18E-08	lb/MMBtu	0.0E+00	1.7E-06
Oth	H-3	41.3	MMBtu/hr	361,574	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.0	17.7	0.0217	lb/MMBtu	0.9	3.9	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.0	1.3	0.082	lb/MMBtu	3.4	14.9	4.90E-07	lb/MMBtu	2.0E-05	8.9E-05	0.04	0.18	1.80E-07	lb/MMBtu	0.0E+00	3.3E-05	1.18E-08	lb/MMBtu	0.0E+00	2.1E-06
11C PS																																											
Cont	H-200	155.2	MMBtu/hr	1,359,718	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.7	0.2745	lb/MMBtu	42.6	186.6	0.0217	lb/MMBtu	3.4	14.7	0.0019	lb/MMBtu	0.3	1.3	0.0075	lb/MMBtu	0.0	5.1	0.082	lb/MMBtu	12.8	56.0	4.90E-07	lb/MMBtu	7.6E-05	3.3E-04	0.15	0.68	1.80E-07	lb/MMBtu	0.0E+00	1.2E-04	1.18E-08	lb/MMBtu	0.0E+00	8.0E-06
Oth	H-300	88.2	MMBtu/hr	772,976	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.1	0.1373	lb/MMBtu	12.1	53.1	0.0217	lb/MMBtu	1.9	8.4	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.0	2.9	0.082	lb/MMBtu	7.3	31.8	4.90E-07	lb/MMBtu	4.3E-05	1.9E-04	0.09	0.38	1.80E-07	lb/MMBtu	0.0E+00	7.0E-05	1.18E-08	lb/MMBtu	0.0E+00	4.5E-06
Coker																																											
SD	H-101	36.8	MMBtu/hr	322,799	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.6	15.8	0.0217	lb/MMBtu	0.8	3.5	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.6	0.082	lb/MMBtu	3.0	13.3	4.90E-07	lb/MMBtu	1.8E-05	7.9E-05	0.04	0.16	1.80E-07	lb/MMBtu	0.0E+00	2.9E-05	1.18E-08	lb/MMBtu	0.0E+00	1.9E-06
SD	H-102	39.0	MMBtu/hr	341,664	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.8	16.7	0.0217	lb/MMBtu	0.8	3.7	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	3.2	14.1	4.90E-07	lb/MMBtu	1.9E-05	8.4E-05	0.04	0.17	1.80E-07	lb/MMBtu	0.0E+00	3.1E-05	1.18E-08	lb/MMBtu	0.0E+00	2.0E-06
SD	H-103	42.5	MMBtu/hr	372,178	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.2	18.2	0.0217	lb/MMBtu	0.9	4.0	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	3.5	15.3	4.90E-07	lb/MMBtu	2.1E-05	9.1E-05	0.04	0.19	1.80E-07	lb/MMBtu	0.0E+00	3.3E-05	1.18E-08	lb/MMBtu	0.0E+00	2.2E-06
SD	H-104	39.9	MMBtu/hr	349,682	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.9	17.1	0.0217	lb/MMBtu	0.9	3.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	3.3	14.4	4.90E-07	lb/MMBtu	2.0E-05	8.6E-05	0.04	0.17	1.80E-07	lb/MMBtu	0.0E+00	3.1E-05	1.18E-08	lb/MMBtu	0.0E+00	2.1E-06
12PS																																											
SD	H-1AN	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.2745	lb/MMBtu	0.0	0.0	0.0217	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0075	lb/MMBtu	0.0	0.0	0.082	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.00	0.00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.18E-08	lb/MMBtu	0.0E+00	0.0E+00
SD	H-1AS	90.6	MMBtu/hr	793,629	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.1	0.2745	lb/MMBtu	24.9	108.9	0.0217	lb/MMBtu	2.0	8.6	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.0	3.0	0.082	lb/MMBtu	7.5	32.7	4.90E-07	lb/MMBtu	4.4E-05	1.9E-04	0.09	0.39	1.80E-07	lb/MMBtu	0.0E+00	7.1E-05	1.18E-08	lb/MMBtu	0.0E+00	4.7E-06
SD	H-1B	138.4	MMBtu/hr	1,212,589	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.3	0.2745	lb/MMBtu	38.0	166.4	0.0217	lb/MMBtu	3.0	13.1	0.0019	lb/MMBtu	0.3	1.1	0.0075	lb/MMBtu	0.0	4.5	0.082	lb/MMBtu	11.4	49.9	4.90E-07	lb/MMBtu	6.8E-05	3.0E-04	0.14	0.60	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	7.1E-06
SD	H-2	92.1	MMBtu/hr	806,627	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.2	0.0360	lb/MMBtu	3.3	14.5	0.0217	lb/MMBtu	2.0	8.7	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.0	3.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	4.5E-05	2.0E-04	0.09	0.40	1.80E-07	lb/MMBtu	0.0E+00	7.3E-05	1.18E-08	lb/MMBtu	0.0E+00	4.7E-06
SD	H-1CN	31.5	MMBtu/hr	276,318	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	3.1	13.5	0.0217	lb/MMBtu	0.7	3.0	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.6	0.082	lb/MMBtu	2.6	11.4	4.90E-07	lb/MMBtu	1.5E-05	6.8E-05	0.03	0.14	1.80E-07	lb/MMBtu	0.0E+00	2.5E-05	1.18E-08	lb/MMBtu	0.0E+00	1.6E-06
SD	H-1CX	170.9	MMBtu/hr	1,497,306	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.0990	lb/MMBtu	16.9	74.1	0.0217	lb/MMBtu	3.7	16.2	0.0019	lb/MMBtu	0.3	1.4	0.0040	lb/MMBtu	0.0	3.0	0.082	lb/MMBtu	14.1	61.7	4.90E-07	lb/MMBtu	8.4E-05	3.7E-04	0.17	0.74	1.80E-07	lb/MMBtu	0.0E+00	1.3E-04	1.18E-08	lb/MMBtu	0.0E+00	8.8E-06
Hydroprocessing																																											
3UF																																											
SD	H-1	80.1	MMBtu/hr	701,691	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.9	0.2745	lb/MMBtu	22.0	96.3	0.0113	lb/MMBtu	0.9	4.0	0.0019	lb/MMBtu	0.1	0.7	0.0040	lb/MMBtu	0.0	1.4	0.082	lb/MMBtu	6.6	28.9	4.90E-07	lb/MMBtu	3.9E-05	1.7E-04	0.04	0.18	1.80E-07	lb/MMBtu	0.0E+00	6.3E-05	1.18E-08	lb/MMBtu	0.0E+00	4.1E-06
SD	H-2	51.0	MMBtu/hr	446,804	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.2745	lb/MMBtu	14.0	61.3	0.0113	lb/MMBtu	0.6	2.5	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.0	0.9	0.082	lb/MMBtu	4.2	18.4	4.90E-07	lb/MMBtu	2.5E-05	1.1E-04	0.03	0.12	1.80E-07	lb/MMBtu	0.0E+00	4.0E-05	1.18E-08	lb/MMBtu	0.0E+00	2.6E-06
SD	F-7	10.7	MMBtu/hr	93,730	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0980	lb/MMBtu	1.0	4.6	0.0113	lb/MMBtu	0.1	0.5	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.9	3.9	4.90E-07	lb/MMBtu	5.2E-06	2.3E-05	0.01	0.02	1.80E-07	lb/MMBtu	0.0E+00	8.4E-06	1.18E-08	lb/MMBtu	0.0E+00	5.5E-07
4UF																																											
Oth	F-1	45.7	MMBtu/hr	400,032	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.1	0.0980	lb/MMBtu	4.5	19.6	0.0086	lb/MMBtu	0.4	1.7	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.0	0.8	0.082	lb/MMBtu	3.8	16.5	4.90E-07	lb/MMBtu	2.2E-05	9.8E-05	0.02	0.08	1.80E-07	lb/MMBtu	0.0E+00	3.6E-05	1.18E-08	lb/MMBtu	0.0E+00	2.4E-06
Oth	F-8A	111.3	MMBtu/hr	975,203	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.6	0.2745	lb/MMBtu	30.6	133.9	0.0086	lb/MMBtu	1.0	4.2	0.0019	lb/MMBtu	0.2	0.9	0.0040	lb/MMBtu	0.0	2.0	0.082	lb/MMBtu	9.2	40.2	4.90E-07	lb/MMBtu	5.5E-05	2.4E-04	0.04	0.19	1.80E-07	lb/MMBtu	0.0E+00	8.8E-05	1.18E-08	lb/MMBtu	0.0E+00	5.7E-06
Oth	F-8B	109.7	MMBtu/hr	960,925	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.6	0.2745	lb/MMBtu	30.1	131.9	0.0086	lb/MMBtu	0.9	4.1	0.0019	lb/MMBtu	0.2	0.9	0.0040	lb/MMBtu	0.0	1.9	0.082	lb/MMBtu	9.0	39.6	4.90E-07	lb/MMBtu	5.4E-05	2.4E-04	0.04	0.19	1.80E-07	lb/MMBtu	0.0E+00	8.6E-05	1.18E-08	lb/MMBtu	0.0E+00	5.7E-06
Oth	F-2	249.6	MMBtu/hr	2,186,121	MMBtu/yr	0.0054	lb/MMBtu	1.3	5.9	0.1863	lb/MMBtu	46.5	203.6	0.0086	lb/MMBtu	2.1	9.4	0.0019	lb/MMBtu	0.5	2.0	0.0040	lb/MMBtu	0.0	4.4	0.082	lb/MMBtu	20.6	90.0	4.90E-07	lb/MMBtu	1.2E-04	5.4E-04	0.10	0.43	1.80E-07	lb/MMBtu	0.0E+00	2.0E-04	1.18E-08	lb/MMBtu	0.0E+00	1.3E-05
Oth	F-3	216.2	MMBtu/hr	1,893,564	MMBtu/yr	0.0054	lb/MMBtu	1.2	5.1	0.2745	lb/MMBtu	59.3	259.9	0.0086	lb/MMBtu	1.9	8.2	0.0019	lb/MMBtu	0.4	1.8	0.0040	lb/MMBtu	0.0	3.8	0.082	lb/MMBtu	17.8	78.0	4.90E-07	lb/MMBtu	1.1E-04	4.6E-04	0.09	0.37	1.80E-07	lb/MMBtu	0.0E+00	1.7E-04	1.18E-08	lb/MMBtu	0.0E+00	1.1E-05
Oth	F-4	137.2	MMBtu/hr	1,201,767	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.2	0.2745	lb/MMBtu	37.7	164.9	0.0086	lb/MMBtu	1.2	5.2	0.0019	lb/MMBtu	0.3	1.1	0.0040	lb/MMBtu	0.0	2.4	0.082	lb/MMBtu	11.3	49.5	4.90E-07	lb/MMBtu	6.7E-05	2.9E-04	0.05	0.24	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	7.1E-06
Oth	F-5	71.8	MMBtu/hr	628,632	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.0980	lb/MMBtu	7.0	30.8	0.0086	lb/MMBtu	0.6	2.7	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.0	1.3	0.082	lb/MMBtu	5.9	25.9	4.90E-07	lb/MMBtu	3.5E-05	1.5E-04	0.03	0.12	1.80E-07	lb/MMBtu	0.0E+00	5.7E-05	1.18E-08	lb/MMBtu	0.0E+00	3.7E-06
Oth	F-6	27.9	MMBtu/hr	244,133	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	2.7	12.0	0.0086	lb/MMBtu	0.2	1.1	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.0	0.5	0.082	lb/MMBtu	2.3	10.1	4.90E-07	lb/MMBtu	1.4E-05	6.0E-05	0.01	0.05	1.80E-07	lb/MMBtu	0.0E+00	2.2E-05	1.18E-08	lb/MMBtu	0.0E+00	1.4E-06
Oth	F-7	42.2	MMBtu/hr	370,088	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.1	18.1	0.0086	lb/MMBtu	0.4	1.6	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	3.5	15.2	4.90E-07	lb/MMBtu	2.1E-05	9.1E-05	0.02	0.07	1.80E-07	lb/MMBtu	0.0E+00	3.3E-05	1.18E-08	lb/MMBtu	0.0E+00	2.2E-06
ARU																																											
Oth	F-200A	138.9	MMBtu/hr	1,216,378	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.3	0.2745	lb/MMBtu	38.1	167.0	0.0217	lb/MMBtu	3.0	13.2	0.0019	lb/MMBtu	0.3	1.1	0.0040	lb/MMBtu	0.0	2.4	0.082	lb/MMBtu	11.4	50.1	4.90E-07	lb/MMBtu	6.8E-05	3.0E-04	0.14	0.60	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	7.2E-06
Oth	F-200B	147.8	MMBtu/hr	1,294,527	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.2745	lb/MMBtu	40.6	177.7	0.0217	lb/MMBtu	3.2	14.0	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.0	2.6	0.082	lb/MMBtu	12.2	53.3	4.90E-07	lb/MMBtu	7.2E-05	3.2E-04	0.15	0.64	1.80E-07	lb/MMBtu	0.0E+00	1.2E-04	1.18E-08	lb/MMBtu	0.0E+00	7.6E-06
BOU																																											
Mod	F-401	18.7	MMBtu/hr	163,632	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0980	lb/MMBtu	1.8	8.0	0.0086	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.0	0.3	0.082	lb/MMBtu	1.5	6.7	4.90E-07	lb/MMBtu	9.2E-06	4.0E-05	0.01	0.03	1.80E-07	lb/MMBtu	0.0E+00	1.5E-05	1.18E-08	lb/MMBtu	0.0E+00	9.6E-07
CFHU																																											
Oth	F-801A	17.5	MMBtu/hr	153,162	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0490	lb/MMBtu	0.9	3.8	0.0074	lb/MMBtu	0.1	0.6	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.3	0.082	lb/MMBtu	1.4	6.3	4.90E-07	lb/MMBtu	8.6E-06	3.8E-05	0.01	0.03	1.80E-07	lb/MMBtu	0.0E+00	1.4E-05	1.18E-08	lb/MMBtu	0.0E+00	9.0E-07
Oth	F-801B	17.5	MMBtu/hr	153,162	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0490	lb/MMBtu	0.9	3.8	0.0074	lb/MMBtu	0.1	0.6	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.3	0.082	lb/MMBtu	1.4	6.3	4.90E-07	lb/MMBtu	8.6E-06	3.8E-05	0.01	0.03	1.80E-07	lb/MMBtu	0.0E+00	1.4E-05	1.18E-08	lb/MMBtu	0.0E+00	9.0E-07
Oth	F-801C	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.0360	lb/MMBtu	0.0	0.0	0.0074	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0040	lb/MMBtu	0.0	0.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.00	0.00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.18E-08	lb/MMBtu	0.0E+00	0.0E+00
CRU																																											
Oth	F-101	35.4	MMBtu/hr	310,496	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0800	lb/MMBtu	2.8	12.4	0.0113	lb/MMBtu	0.4	1.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.6	0.082	lb/MMBtu	2.9	12.8	4.90E-07	lb/MMBtu	1.7E-05	7.6E-05	0.02	0.08	1.80E-07	lb/MMBtu	0.0E+00	2.8E-05	1.18E-08	lb/MMBtu	0.0E+00	1.8E-06
Oth	F-102	13.4	MMBtu/hr	117,788	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0800	lb/MMBtu	1.1	4.7	0.0113	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	1.1	4.9	4.90E-07	lb/MMBtu	6.6E-06	2.9E-05	0.01	0.03	1.80E-07	lb/MMBtu	0.0E+00	1.1E-05	1.18E-08	lb/MMBtu	0.0E+00	6.9E-07
DDU																																											
Oth	WB-301	24.6	MMBtu/hr	215,727	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0346	lb/MMBtu	0.9	3.7	0.0217	lb/MMBtu	0.5	2.3	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.0	0.4	0.040	lb/MMBtu	1.0	4.3	4.90E-07	lb/MMBtu	1.2E-05	5.3E-05	0.02	0.11	1.80E-07	lb/MMBtu	0.0E+00	1.9E-05	1.18E-08	lb/MMBtu	0.0E+00	1.3E-06
Oth	WB-302	59.5	MMBtu/hr	521,217	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.4	0.0300	lb/MMBtu	1.8	7.8	0.0217	lb/MMBtu	1.3	5.6	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.0	1.0	0.040	lb/MMBtu	2.4	10.4	4.90E-07	lb/MMBtu	2.9E-05	1.3E-04	0.06	0.26	1.80E-07	lb/MMBtu	0.0E+00	4.7E-05	1.18E-08	lb/MMBtu	0.0E+00	3.1E-06
ISOM																																											
Mod	H-1	171.4	MMBtu/hr	1,501,457	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.2745	lb/MMBtu	47.1	206.1	0.0217	lb/MMBtu	3.7	16.3	0.0019	lb/MMBtu	0.3	1.4	0.0040	lb/MMBtu	0.0	3.0	0.082	lb/MMBtu	14.1	61.8	4.90E-07	lb/MMBtu	8.4E-05	3.7E-04	0.17	0.75	1.80E-07	lb/MMBtu	0.0E+00	1.4E-04	1.18E-08	lb/MMBtu	0.0E+00	8.8E-06
HU																																											
Oth	B-501	180.2	MMBtu/hr	1,578,427	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.3	0.0675	lb/MMBtu	12.2	53.3	0.0703	lb/MMBtu	12.7	55.5	0.0019	lb/MMBtu	0.3	1.5	0.0075	lb/MMBtu	0.0	5.9	0.02	lb/MMBtu	3.6	15.8	4.90E-07	lb/MMBtu	8.8E-05	3.9E-04	0.58	2.55	1.80E-07	lb/MMBtu	0.0E+00	1.4E-04	1.18E-08	lb/MMBtu	0.0E+00	9.3E-06
Utilities																																											
1SPS																																											
SD	Boiler 3	31.4	MMBtu/hr	275,414	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.1570	lb/MMBtu	4.9	21.6	0.0217	lb/MMBtu	0.7	3.0	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.0	1.0	0.049	lb/MMBtu	1.5	6.7	4.90E-07	lb/MMBtu	1.5E-05	6.8E-05	0.03	0.14	1.80E-07	lb/MMBtu	0.0E+00	2.5E-05	1.18E-08	lb/MMBtu	0.0E+00	1.6E-06
SD	Boiler 4	41.4	MMBtu/hr	362,736	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.1570	lb/MMBtu	6.5	28.5	0.0217	lb/MMBtu	0.9	3.9	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.0	1.4	0.049	lb/MMBtu	2.0	8.9	4.90E-07	lb/MMBtu	2.0E-05	8.9E-05	0.04	0.18	1.80E-07	lb/MMBtu	0.0E+00	3.3E-05	1.18E-08	lb/MMBtu	0.0E+00	2.1E-06
SD	Boiler 5	60.5	MMBtu/hr	529,591	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.4	0.0930	lb/MMBtu	5.6	24.6	0.0217	lb/MMBtu	1.3	5.7	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.0	2.0	0.248	lb/MMBtu	15.0	65.7	4.90E-07	lb/MMBtu	3.0E-05	1.3E-04	0.06	0.26	1.80E-07	lb/MMBtu	0.0E+00	4.8E-05	1.18E-08	lb/MMBtu	0.0E+00	3.1E-06
SD	Boiler 6	17.9	MMBtu/hr	156,407	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0930	lb/MMBtu	1.7	7.3	0.0217	lb/MMBtu	0.4	1.7	0.0019	lb/MMBtu	0.0	0.1	0.0075	lb/MMBtu	0.0	0.6	0.248	lb/MMBtu	4.4	19.4	4.90E-07	lb/MMBtu	8.8E-06	3.8E-05	0.02	0.08	1.80E-07	lb/MMBtu	0.0E+00	1.4E-05	1.18E-08	lb/MMBtu	0.0E+00	9.2E-07
SD	Boiler 7	75.9	MMBtu/hr	664,748	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.0930	lb/MMBtu	7.1	30.9	0.0217	lb/MMBtu	1.6	7.2	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.0	2.5	0.248	lb/MMBtu	18.8	82.4	4.90E-07	lb/MMBtu	3.7E-05	1.6E-04	0.08	0.33	1.80E-07	lb/MMBtu	0.0E+00	6.0E-05	1.18E-08	lb/MMBtu	0.0E+00	3.9E-06
Lakefront																																											
SD	FBI	46,632	tons feed			0.34

Table C.15. 2002 Combustion Emissions

Process Heaters and Boilers

Code	Process Unit	Usage				VOC EF	VOC Unit	VOC lb/hr[1]	VOC tpy	NO_x EF	NO_x Unit	NO_x lb/hr[1]	NO_x tpy	SO_2 EF	SO_2 Unit	SO_2 lb/hr[1]	SO_2 tpy	PM (Filterable) EF	PM (Filterable) Unit	PM (Filterable) lb/hr[1]	PM (Filterable) tpy	$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[2] EF	$PM_{10}/PM_{2.5}$ Unit	$PM_{10}/PM_{2.5}$ lb/hr[1]	$PM_{10}/PM_{2.5}$ tpy	CO EF	CO Unit	CO lb/hr[1]	CO tpy	Pb EF	Pb Unit	Pb lb/hr[1]	Pb tpy	H_2SO_4 Mist lb/hr[1]	H_2SO_4 Mist tpy	Hg EF	Hg Unit	Hg lb/hr[1]	Hg tpy	Be EF	Be Unit	Be lb/hr[1]	Be tpy
Crude and Coking																																									
11A PS																																									
Oth	H-1X	113.3	MMBtu/hr	992,610	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.7	0.1660	lb/MMBtu	18.8	82.4	0.0210	lb/MMBtu	2.4	10.4	0.0019	lb/MMBtu	0.2	0.9	0.0075	lb/MMBtu	0.0	3.7	0.082	lb/MMBtu	9.3	40.9	4.90E-07	lb/MMBtu	5.6E-05	2.4E-04	0.11	0.48	1.80E-07	lb/MMBtu	0.0E+00	8.9E-05	1.18E-08	lb/MMBtu	0.0E+00	5.8E-06
Oth	H-2	22.5	MMBtu/hr	196,812	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0980	lb/MMBtu	2.2	9.6	0.0210	lb/MMBtu	0.5	2.1	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	1.9	8.1	4.90E-07	lb/MMBtu	1.1E-05	4.8E-05	0.02	0.09	1.80E-07	lb/MMBtu	0.0E+00	1.8E-05	1.18E-08	lb/MMBtu	0.0E+00	1.2E-06
Oth	H-3	42.2	MMBtu/hr	369,799	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.1	18.1	0.0210	lb/MMBtu	0.9	3.9	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.0	1.4	0.082	lb/MMBtu	3.5	15.2	4.90E-07	lb/MMBtu	2.1E-05	9.1E-05	0.04	0.18	1.80E-07	lb/MMBtu	0.0E+00	3.3E-05	1.18E-08	lb/MMBtu	0.0E+00	2.2E-06
11C PS																																									
Cont	H-200	160.0	MMBtu/hr	1,401,452	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.8	0.2745	lb/MMBtu	43.9	192.4	0.0210	lb/MMBtu	3.4	14.7	0.0019	lb/MMBtu	0.3	1.3	0.0075	lb/MMBtu	0.0	5.2	0.082	lb/MMBtu	13.2	57.7	4.90E-07	lb/MMBtu	7.8E-05	3.4E-04	0.15	0.67	1.80E-07	lb/MMBtu	0.0E+00	1.3E-04	1.18E-08	lb/MMBtu	0.0E+00	8.2E-06
Oth	H-300	77.3	MMBtu/hr	677,564	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.1373	lb/MMBtu	10.6	46.5	0.0210	lb/MMBtu	1.6	7.1	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.0	2.5	0.082	lb/MMBtu	6.4	27.9	4.90E-07	lb/MMBtu	3.8E-05	1.7E-04	0.07	0.33	1.80E-07	lb/MMBtu	0.0E+00	6.1E-05	1.18E-08	lb/MMBtu	0.0E+00	4.0E-06
Coker																																									
SD	H-101	38.4	MMBtu/hr	336,228	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.8	16.5	0.0210	lb/MMBtu	0.8	3.5	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	3.2	13.8	4.90E-07	lb/MMBtu	1.9E-05	8.2E-05	0.04	0.16	1.80E-07	lb/MMBtu	0.0E+00	3.0E-05	1.18E-08	lb/MMBtu	0.0E+00	2.0E-06
SD	H-102	36.6	MMBtu/hr	320,323	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.6	15.7	0.0210	lb/MMBtu	0.8	3.4	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.6	0.082	lb/MMBtu	3.0	13.2	4.90E-07	lb/MMBtu	1.8E-05	7.9E-05	0.04	0.15	1.80E-07	lb/MMBtu	0.0E+00	2.9E-05	1.18E-08	lb/MMBtu	0.0E+00	1.9E-06
SD	H-103	40.9	MMBtu/hr	358,069	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.0	17.6	0.0210	lb/MMBtu	0.9	3.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	3.4	14.7	4.90E-07	lb/MMBtu	2.0E-05	8.8E-05	0.04	0.17	1.80E-07	lb/MMBtu	0.0E+00	3.2E-05	1.18E-08	lb/MMBtu	0.0E+00	2.1E-06
SD	H-104	36.6	MMBtu/hr	320,359	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.6	15.7	0.0210	lb/MMBtu	0.8	3.4	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.6	0.082	lb/MMBtu	3.0	13.2	4.90E-07	lb/MMBtu	1.8E-05	7.9E-05	0.04	0.15	1.80E-07	lb/MMBtu	0.0E+00	2.9E-05	1.18E-08	lb/MMBtu	0.0E+00	1.9E-06
12PS																																									
SD	H-1AN	82.3	MMBtu/hr	721,198	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.9	0.2745	lb/MMBtu	22.6	99.0	0.0210	lb/MMBtu	1.7	7.6	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.0	2.7	0.082	lb/MMBtu	6.8	29.7	4.90E-07	lb/MMBtu	4.0E-05	1.8E-04	0.08	0.35	1.80E-07	lb/MMBtu	0.0E+00	6.5E-05	1.18E-08	lb/MMBtu	0.0E+00	4.2E-06
SD	H-1AS	65.0	MMBtu/hr	569,232	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.5	0.2745	lb/MMBtu	17.8	78.1	0.0210	lb/MMBtu	1.4	6.0	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.0	2.1	0.082	lb/MMBtu	5.4	23.4	4.90E-07	lb/MMBtu	3.2E-05	1.4E-04	0.06	0.27	1.80E-07	lb/MMBtu	0.0E+00	5.1E-05	1.18E-08	lb/MMBtu	0.0E+00	3.3E-06
SD	H-1B	191.5	MMBtu/hr	1,677,910	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.5	0.2745	lb/MMBtu	52.6	230.3	0.0210	lb/MMBtu	4.0	17.6	0.0019	lb/MMBtu	0.4	1.6	0.0075	lb/MMBtu	0.0	6.3	0.082	lb/MMBtu	15.8	69.1	4.90E-07	lb/MMBtu	9.4E-05	4.1E-04	0.18	0.81	1.80E-07	lb/MMBtu	0.0E+00	1.5E-04	1.18E-08	lb/MMBtu	0.0E+00	9.9E-06
SD	H-2	131.7	MMBtu/hr	1,153,304	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.1	0.0360	lb/MMBtu	4.7	20.8	0.0210	lb/MMBtu	2.8	12.1	0.0019	lb/MMBtu	0.2	1.1	0.0075	lb/MMBtu	0.0	4.3	0.0001	lb/MMBtu	0.0	0.1	4.90E-07	lb/MMBtu	6.5E-05	2.8E-04	0.13	0.55	1.80E-07	lb/MMBtu	0.0E+00	1.0E-04	1.18E-08	lb/MMBtu	0.0E+00	6.8E-06
SD	H-1CN	55.5	MMBtu/hr	485,870	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.3	0.0980	lb/MMBtu	5.4	23.8	0.0210	lb/MMBtu	1.2	5.1	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.0	1.0	0.082	lb/MMBtu	4.6	20.0	4.90E-07	lb/MMBtu	2.7E-05	1.2E-04	0.05	0.23	1.80E-07	lb/MMBtu	0.0E+00	4.4E-05	1.18E-08	lb/MMBtu	0.0E+00	2.9E-06
SD	H-1CX	262.7	MMBtu/hr	2,301,611	MMBtu/yr	0.0054	lb/MMBtu	1.4	6.2	0.0990	lb/MMBtu	26.0	113.9	0.0210	lb/MMBtu	5.5	24.1	0.0019	lb/MMBtu	0.5	2.1	0.0040	lb/MMBtu	0.0	4.0	0.082	lb/MMBtu	21.6	94.8	4.90E-07	lb/MMBtu	1.3E-04	5.6E-04	0.25	1.11	1.80E-07	lb/MMBtu	0.0E+00	2.1E-04	1.18E-08	lb/MMBtu	0.0E+00	1.4E-05
Hydroprocessing																																									
3UF																																									
SD	H-1	86.0	MMBtu/hr	753,382	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.0	0.2745	lb/MMBtu	23.6	103.4	0.0074	lb/MMBtu	0.6	2.8	0.0019	lb/MMBtu	0.2	0.7	0.0040	lb/MMBtu	0.0	1.5	0.082	lb/MMBtu	7.1	31.0	4.90E-07	lb/MMBtu	4.2E-05	1.8E-04	0.03	0.13	1.80E-07	lb/MMBtu	0.0E+00	6.8E-05	1.18E-08	lb/MMBtu	0.0E+00	4.4E-06
SD	H-2	91.4	MMBtu/hr	800,817	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.2	0.2745	lb/MMBtu	25.1	109.9	0.0074	lb/MMBtu	0.7	3.0	0.0019	lb/MMBtu	0.2	0.7	0.0040	lb/MMBtu	0.0	1.6	0.082	lb/MMBtu	7.5	33.0	4.90E-07	lb/MMBtu	4.5E-05	2.0E-04	0.03	0.14	1.80E-07	lb/MMBtu	0.0E+00	7.2E-05	1.18E-08	lb/MMBtu	0.0E+00	4.7E-06
SD	F-7	14.3	MMBtu/hr	125,616	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0980	lb/MMBtu	1.4	6.2	0.0074	lb/MMBtu	0.1	0.5	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.3	0.082	lb/MMBtu	1.2	5.2	4.90E-07	lb/MMBtu	7.0E-06	3.1E-05	0.00	0.02	1.80E-07	lb/MMBtu	0.0E+00	1.1E-05	1.18E-08	lb/MMBtu	0.0E+00	7.4E-07
4UF																																									
Oth	F-1	31.7	MMBtu/hr	277,335	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	3.1	13.6	0.0090	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.6	0.082	lb/MMBtu	2.6	11.4	4.90E-07	lb/MMBtu	1.6E-05	6.8E-05	0.01	0.06	1.80E-07	lb/MMBtu	0.0E+00	2.5E-05	1.18E-08	lb/MMBtu	0.0E+00	1.6E-06
Oth	F-8A	71.9	MMBtu/hr	629,825	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.2745	lb/MMBtu	19.7	86.4	0.0090	lb/MMBtu	0.6	2.8	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.0	1.3	0.082	lb/MMBtu	5.9	25.9	4.90E-07	lb/MMBtu	3.5E-05	1.5E-04	0.03	0.13	1.80E-07	lb/MMBtu	0.0E+00	5.7E-05	1.18E-08	lb/MMBtu	0.0E+00	3.7E-06
Oth	F-8B	67.5	MMBtu/hr	591,622	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.6	0.2745	lb/MMBtu	18.5	81.2	0.0090	lb/MMBtu	0.6	2.7	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.0	1.2	0.082	lb/MMBtu	5.6	24.4	4.90E-07	lb/MMBtu	3.3E-05	1.5E-04	0.03	0.12	1.80E-07	lb/MMBtu	0.0E+00	5.3E-05	1.18E-08	lb/MMBtu	0.0E+00	3.5E-06
Oth	F-2	164.4	MMBtu/hr	1,439,968	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.9	0.1863	lb/MMBtu	30.6	134.1	0.0090	lb/MMBtu	1.5	6.5	0.0019	lb/MMBtu	0.3	1.3	0.0040	lb/MMBtu	0.0	2.9	0.082	lb/MMBtu	13.5	59.3	4.90E-07	lb/MMBtu	8.1E-05	3.5E-04	0.07	0.30	1.80E-07	lb/MMBtu	0.0E+00	1.3E-04	1.18E-08	lb/MMBtu	0.0E+00	8.5E-06
Oth	F-3	138.9	MMBtu/hr	1,216,619	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.3	0.2745	lb/MMBtu	38.1	167.0	0.0090	lb/MMBtu	1.2	5.5	0.0019	lb/MMBtu	0.3	1.1	0.0040	lb/MMBtu	0.0	2.4	0.082	lb/MMBtu	11.4	50.1	4.90E-07	lb/MMBtu	6.8E-05	3.0E-04	0.06	0.25	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	7.2E-06
Oth	F-4	87.3	MMBtu/hr	764,321	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.1	0.2745	lb/MMBtu	24.0	104.9	0.0090	lb/MMBtu	0.8	3.4	0.0019	lb/MMBtu	0.2	0.7	0.0040	lb/MMBtu	0.0	1.5	0.082	lb/MMBtu	7.2	31.5	4.90E-07	lb/MMBtu	4.3E-05	1.9E-04	0.04	0.16	1.80E-07	lb/MMBtu	0.0E+00	6.9E-05	1.18E-08	lb/MMBtu	0.0E+00	4.5E-06
Oth	F-5	45.0	MMBtu/hr	394,172	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.1	0.0980	lb/MMBtu	4.4	19.3	0.0090	lb/MMBtu	0.4	1.8	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.0	0.8	0.082	lb/MMBtu	3.7	16.2	4.90E-07	lb/MMBtu	2.2E-05	9.7E-05	0.02	0.08	1.80E-07	lb/MMBtu	0.0E+00	3.5E-05	1.18E-08	lb/MMBtu	0.0E+00	2.3E-06
Oth	F-6	29.5	MMBtu/hr	258,845	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	2.9	12.7	0.0090	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.0	0.5	0.082	lb/MMBtu	2.4	10.7	4.90E-07	lb/MMBtu	1.4E-05	6.3E-05	0.01	0.05	1.80E-07	lb/MMBtu	0.0E+00	2.3E-05	1.18E-08	lb/MMBtu	0.0E+00	1.5E-06
Oth	F-7	28.2	MMBtu/hr	246,826	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	2.8	12.1	0.0090	lb/MMBtu	0.3	1.1	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.0	0.5	0.082	lb/MMBtu	2.3	10.2	4.90E-07	lb/MMBtu	1.4E-05	6.0E-05	0.01	0.05	1.80E-07	lb/MMBtu	0.0E+00	2.2E-05	1.18E-08	lb/MMBtu	0.0E+00	1.5E-06
ARU																																									
Oth	F-200A	125.5	MMBtu/hr	1,099,020	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.0	0.2745	lb/MMBtu	34.4	150.8	0.0210	lb/MMBtu	2.6	11.5	0.0019	lb/MMBtu	0.2	1.0	0.0040	lb/MMBtu	0.0	2.2	0.082	lb/MMBtu	10.3	45.3	4.90E-07	lb/MMBtu	6.1E-05	2.7E-04	0.12	0.53	1.80E-07	lb/MMBtu	0.0E+00	9.9E-05	1.18E-08	lb/MMBtu	0.0E+00	6.5E-06
Oth	F-200B	134.2	MMBtu/hr	1,175,552	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.2	0.2745	lb/MMBtu	36.8	161.4	0.0210	lb/MMBtu	2.8	12.3	0.0019	lb/MMBtu	0.2	1.1	0.0040	lb/MMBtu	0.0	2.4	0.082	lb/MMBtu	11.1	48.4	4.90E-07	lb/MMBtu	6.6E-05	2.9E-04	0.13	0.57	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	6.9E-06
BOU																																									
Mod	F-401	8.9	MMBtu/hr	78,099	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.2	0.0980	lb/MMBtu	0.9	3.8	0.0090	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.7	3.2	4.90E-07	lb/MMBtu	4.4E-06	1.9E-05	0.00	0.02	1.80E-07	lb/MMBtu	0.0E+00	7.0E-06	1.18E-08	lb/MMBtu	0.0E+00	4.6E-07
CFHU																																									
Oth	F-801A	15.7	MMBtu/hr	137,553	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0490	lb/MMBtu	0.8	3.4	0.0128	lb/MMBtu	0.2	0.9	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.3	0.082	lb/MMBtu	1.3	5.7	4.90E-07	lb/MMBtu	7.7E-06	3.4E-05	0.01	0.04	1.80E-07	lb/MMBtu	0.0E+00	1.2E-05	1.18E-08	lb/MMBtu	0.0E+00	8.1E-07
Oth	F-801B	14.0	MMBtu/hr	123,008	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0490	lb/MMBtu	0.7	3.0	0.0128	lb/MMBtu	0.2	0.8	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	1.2	5.1	4.90E-07	lb/MMBtu	6.9E-06	3.0E-05	0.01	0.04	1.80E-07	lb/MMBtu	0.0E+00	1.1E-05	1.18E-08	lb/MMBtu	0.0E+00	7.2E-07
Oth	F-801C	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.0360	lb/MMBtu	0.0	0.0	0.0128	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0040	lb/MMBtu	0.0	0.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.00	0.00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.18E-08	lb/MMBtu	0.0E+00	0.0E+00
CRU																																									
Oth	F-101	22.1	MMBtu/hr	194,026	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0800	lb/MMBtu	1.8	7.8	0.0074	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.0	0.4	0.082	lb/MMBtu	1.8	8.0	4.90E-07	lb/MMBtu	1.1E-05	4.8E-05	0.01	0.03	1.80E-07	lb/MMBtu	0.0E+00	1.7E-05	1.18E-08	lb/MMBtu	0.0E+00	1.1E-06
Oth	F-102	16.5	MMBtu/hr	144,932	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0800	lb/MMBtu	1.3	5.8	0.0074	lb/MMBtu	0.1	0.5	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.3	0.082	lb/MMBtu	1.4	6.0	4.90E-07	lb/MMBtu	8.1E-06	3.6E-05	0.01	0.02	1.80E-07	lb/MMBtu	0.0E+00	1.3E-05	1.18E-08	lb/MMBtu	0.0E+00	8.5E-07
DDU																																									
Oth	WB-301	28.1	MMBtu/hr	245,999	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0346	lb/MMBtu	1.0	4.3	0.0210	lb/MMBtu	0.6	2.6	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.0	0.5	0.040	lb/MMBtu	1.1	4.9	4.90E-07	lb/MMBtu	1.4E-05	6.0E-05	0.03	0.12	1.80E-07	lb/MMBtu	0.0E+00	2.2E-05	1.18E-08	lb/MMBtu	0.0E+00	1.4E-06
Oth	WB-302	61.6	MMBtu/hr	539,467	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.5	0.0300	lb/MMBtu	1.8	8.1	0.0210	lb/MMBtu	1.3	5.7	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.0	1.1	0.040	lb/MMBtu	2.5	10.8	4.90E-07	lb/MMBtu	3.0E-05	1.3E-04	0.06	0.26	1.80E-07	lb/MMBtu	0.0E+00	4.9E-05	1.18E-08	lb/MMBtu	0.0E+00	3.2E-06
ISOM																																									
Mod	H-1	138.0	MMBtu/hr	1,208,953	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.3	0.2745	lb/MMBtu	37.9	165.9	0.0210	lb/MMBtu	2.9	12.7	0.0019	lb/MMBtu	0.3	1.1	0.0040	lb/MMBtu	0.0	2.4	0.082	lb/MMBtu	11.4	49.8	4.90E-07	lb/MMBtu	6.8E-05	3.0E-04	0.13	0.58	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	7.1E-06
HU																																									
Oth	B-501	155.4	MMBtu/hr	1,361,598	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.7	0.0675	lb/MMBtu	10.5	46.0	0.0672	lb/MMBtu	10.4	45.7	0.0019	lb/MMBtu	0.3	1.3	0.0075	lb/MMBtu	0.0	5.1	0.02	lb/MMBtu	3.1	13.6	4.90E-07	lb/MMBtu	7.6E-05	3.3E-04	0.48	2.10	1.80E-07	lb/MMBtu	0.0E+00	1.2E-04	1.18E-08	lb/MMBtu	0.0E+00	8.0E-06
Utilities																																									
1SPS																																									
SD	Boiler 3	63.8	MMBtu/hr	558,791	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.5	0.1570	lb/MMBtu	10.0	43.9	0.0210	lb/MMBtu	1.3	5.9	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.0	2.1	0.049	lb/MMBtu	3.1	13.7	4.90E-07	lb/MMBtu	3.1E-05	1.4E-04	0.06	0.27	1.80E-07	lb/MMBtu	0.0E+00	5.0E-05	1.18E-08	lb/MMBtu	0.0E+00	3.3E-06
SD	Boiler 4	65.0	MMBtu/hr	569,196	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.5	0.1570	lb/MMBtu	10.2	44.7	0.0210	lb/MMBtu	1.4	6.0	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.0	2.1	0.049	lb/MMBtu	3.2	13.9	4.90E-07	lb/MMBtu	3.2E-05	1.4E-04	0.06	0.27	1.80E-07	lb/MMBtu	0.0E+00	5.1E-05	1.18E-08	lb/MMBtu	0.0E+00	3.3E-06
SD	Boiler 5	31.2	MMBtu/hr	273,601	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0930	lb/MMBtu	2.9	12.7	0.0210	lb/MMBtu	0.7	2.9	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.0	1.0	0.248	lb/MMBtu	7.7	33.9	4.90E-07	lb/MMBtu	1.5E-05	6.7E-05	0.03	0.13	1.80E-07	lb/MMBtu	0.0E+00	2.5E-05	1.18E-08	lb/MMBtu	0.0E+00	1.6E-06
SD	Boiler 6	25.8	MMBtu/hr	225,690	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0930	lb/MMBtu	2.4	10.5	0.0210	lb/MMBtu	0.5	2.4	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.0	0.8	0.248	lb/MMBtu	6.4	28.0	4.90E-07	lb/MMBtu	1.3E-05	5.5E-05	0.02	0.11	1.80E-07	lb/MMBtu	0.0E+00	2.0E-05	1.18E-08	lb/MMBtu	0.0E+00	1.3E-06
SD	Boiler 7	47.8	MMBtu/hr	418,794	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0930	lb/MMBtu	4.4	19.5	0.0210	lb/MMBtu	1.0	4.4	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.0	1.6	0.248	lb/MMBtu	11.9	51.9	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.05	0.20	1.80E-07	lb/MMBtu	0.0E+00	3.8E-05	1.18E-08	lb/MMBtu	0.0E+00	2.5E-06
Lakefront																																									
SD	FBI	17	MMGal/yr	86,369	tons feed	0.0305	lb/unit feed	0.3	1.3	4.7574

Table C.16. 2003 Combustion Emissions

Process Heaters and Boilers

Code	Process Unit	Usage			VOC EF	VOC Unit	VOC lb/hr[1]	VOC tpy	NO_x EF	NO_x Unit	NO_x lb/hr[1]	NO_x tpy	SO_2 EF	SO_2 Unit	SO_2 lb/hr[1]	SO_2 tpy	PM (Filterable) EF	PM (Filterable) Unit	PM (Filterable) lb/hr[1]	PM (Filterable) tpy	$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[2] EF	$PM_{10}/PM_{2.5}$ Unit	$PM_{10}/PM_{2.5}$ lb/hr[1]	$PM_{10}/PM_{2.5}$ tpy	CO EF	CO Unit	CO lb/hr[1]	CO tpy	Pb EF	Pb Unit	Pb lb/hr[1]	Pb tpy	H_2SO_4 Mist lb/hr[1]	H_2SO_4 Mist tpy	Hg EF	Hg Unit	Hg lb/hr[1]	Hg tpy	Be EF	Be Unit	Be lb/hr[1]	Be tpy
Crude and Coking																																										
11A PS																																										
Oth	H-1X	148.1	MMBtu/hr	1,297,532	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.1660	lb/MMBtu	24.6	107.7	0.0200	lb/MMBtu	3.0	13.0	0.0019	lb/MMBtu	0.3	1.2	0.0075	lb/MMBtu	1.1	4.8	0.082	lb/MMBtu	12.2	53.4	4.90E-07	lb/MMBtu	7.3E-05	3.2E-04	0.14	0.60	1.80E-07	lb/MMBtu	2.7E-05	1.2E-04	1.18E-08	lb/MMBtu	1.7E-06	7.6E-06
Oth	H-2	24.2	MMBtu/hr	211,688	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0980	lb/MMBtu	2.4	10.4	0.0200	lb/MMBtu	0.5	2.1	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	2.0	8.7	4.90E-07	lb/MMBtu	1.2E-05	5.2E-05	0.02	0.10	1.80E-07	lb/MMBtu	4.3E-06	1.9E-05	1.18E-08	lb/MMBtu	2.8E-07	1.2E-06
Oth	H-3	36.9	MMBtu/hr	322,837	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.6	15.8	0.0200	lb/MMBtu	0.7	3.2	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.3	1.2	0.082	lb/MMBtu	3.0	13.3	4.90E-07	lb/MMBtu	1.8E-05	7.9E-05	0.03	0.15	1.80E-07	lb/MMBtu	6.6E-06	2.9E-05	1.18E-08	lb/MMBtu	4.3E-07	1.9E-06
11C PS																																										
Cont	H-200	91.2	MMBtu/hr	798,797	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.2	0.2745	lb/MMBtu	25.0	109.6	0.0200	lb/MMBtu	1.8	8.0	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.7	3.0	0.082	lb/MMBtu	7.5	32.9	4.90E-07	lb/MMBtu	4.5E-05	2.0E-04	0.08	0.37	1.80E-07	lb/MMBtu	1.6E-05	7.2E-05	1.18E-08	lb/MMBtu	1.1E-06	4.7E-06
Oth	H-300	74.4	MMBtu/hr	651,599	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.1373	lb/MMBtu	10.2	44.7	0.0200	lb/MMBtu	1.5	6.5	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.6	2.4	0.082	lb/MMBtu	6.1	26.8	4.90E-07	lb/MMBtu	3.6E-05	1.6E-04	0.07	0.30	1.80E-07	lb/MMBtu	1.3E-05	5.9E-05	1.18E-08	lb/MMBtu	8.8E-07	3.8E-06
Coker																																										
SD	H-101	39.6	MMBtu/hr	346,501	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.9	17.0	0.0200	lb/MMBtu	0.8	3.5	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.3	14.3	4.90E-07	lb/MMBtu	1.9E-05	8.5E-05	0.04	0.16	1.80E-07	lb/MMBtu	7.1E-06	3.1E-05	1.18E-08	lb/MMBtu	4.7E-07	2.0E-06
SD	H-102	31.4	MMBtu/hr	274,871	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	3.1	13.5	0.0200	lb/MMBtu	0.6	2.7	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.6	11.3	4.90E-07	lb/MMBtu	1.5E-05	6.7E-05	0.03	0.13	1.80E-07	lb/MMBtu	5.6E-06	2.5E-05	1.18E-08	lb/MMBtu	3.7E-07	1.6E-06
SD	H-103	33.7	MMBtu/hr	294,923	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.3	14.5	0.0200	lb/MMBtu	0.7	2.9	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.8	12.1	4.90E-07	lb/MMBtu	1.7E-05	7.2E-05	0.03	0.14	1.80E-07	lb/MMBtu	6.1E-06	2.7E-05	1.18E-08	lb/MMBtu	4.0E-07	1.7E-06
SD	H-104	31.2	MMBtu/hr	273,055	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	3.1	13.4	0.0200	lb/MMBtu	0.6	2.7	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.6	11.2	4.90E-07	lb/MMBtu	1.5E-05	6.7E-05	0.03	0.13	1.80E-07	lb/MMBtu	5.6E-06	2.5E-05	1.18E-08	lb/MMBtu	3.7E-07	1.6E-06
12PS																																										
SD	H-1AN	81.0	MMBtu/hr	709,998	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.9	0.2745	lb/MMBtu	22.2	97.5	0.0200	lb/MMBtu	1.6	7.1	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.6	2.6	0.082	lb/MMBtu	6.7	29.2	4.90E-07	lb/MMBtu	4.0E-05	1.7E-04	0.07	0.33	1.80E-07	lb/MMBtu	1.5E-05	6.4E-05	1.18E-08	lb/MMBtu	9.5E-07	4.2E-06
SD	H-1AS	61.0	MMBtu/hr	534,293	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.4	0.2745	lb/MMBtu	16.7	73.3	0.0200	lb/MMBtu	1.2	5.3	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.5	2.0	0.082	lb/MMBtu	5.0	22.0	4.90E-07	lb/MMBtu	3.0E-05	1.3E-04	0.06	0.25	1.80E-07	lb/MMBtu	1.1E-05	4.8E-05	1.18E-08	lb/MMBtu	7.2E-07	3.1E-06
SD	H-1B	170.2	MMBtu/hr	1,490,723	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.2745	lb/MMBtu	46.7	204.6	0.0200	lb/MMBtu	3.4	14.9	0.0019	lb/MMBtu	0.3	1.4	0.0075	lb/MMBtu	1.3	5.6	0.082	lb/MMBtu	14.0	61.4	4.90E-07	lb/MMBtu	8.3E-05	3.7E-04	0.16	0.68	1.80E-07	lb/MMBtu	3.1E-05	1.3E-04	1.18E-08	lb/MMBtu	2.0E-06	8.8E-06
SD	H-2	129.0	MMBtu/hr	1,130,066	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.0	0.0360	lb/MMBtu	4.6	20.3	0.0200	lb/MMBtu	2.6	11.3	0.0019	lb/MMBtu	0.2	1.1	0.0075	lb/MMBtu	1.0	4.2	0.0001	lb/MMBtu	0.0	0.1	4.90E-07	lb/MMBtu	6.3E-05	2.8E-04	0.12	0.52	1.80E-07	lb/MMBtu	2.3E-05	1.0E-04	1.18E-08	lb/MMBtu	1.5E-06	6.6E-06
SD	H-1CN	46.1	MMBtu/hr	403,538	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.1	0.0980	lb/MMBtu	4.5	19.8	0.0200	lb/MMBtu	0.9	4.0	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.8	16.6	4.90E-07	lb/MMBtu	2.3E-05	9.9E-05	0.04	0.19	1.80E-07	lb/MMBtu	8.3E-06	3.6E-05	1.18E-08	lb/MMBtu	5.4E-07	2.4E-06
SD	H-1CX	248.3	MMBtu/hr	2,174,836	MMBtu/yr	0.0054	lb/MMBtu	1.3	5.9	0.0990	lb/MMBtu	24.8	107.7	0.0200	lb/MMBtu	5.0	21.7	0.0019	lb/MMBtu	0.5	2.0	0.0040	lb/MMBtu	0.9	4.0	0.082	lb/MMBtu	20.4	89.6	4.90E-07	lb/MMBtu	1.2E-04	5.3E-04	0.23	1.00	1.80E-07	lb/MMBtu	4.5E-05	2.0E-04	1.18E-08	lb/MMBtu	2.9E-06	1.3E-05
Hydroprocessing																																										
3UF																																										
SD	H-1	87.4	MMBtu/hr	765,623	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.1	0.2745	lb/MMBtu	24.0	105.1	0.0069	lb/MMBtu	0.6	2.6	0.0019	lb/MMBtu	0.2	0.7	0.0040	lb/MMBtu	0.3	1.5	0.082	lb/MMBtu	7.2	31.5	4.90E-07	lb/MMBtu	4.3E-05	1.9E-04	0.03	0.12	1.80E-07	lb/MMBtu	1.6E-05	6.9E-05	1.18E-08	lb/MMBtu	1.0E-06	4.5E-06
SD	H-2	92.8	MMBtu/hr	812,955	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.2	0.2745	lb/MMBtu	25.5	111.6	0.0069	lb/MMBtu	0.6	2.8	0.0019	lb/MMBtu	0.2	0.8	0.0040	lb/MMBtu	0.4	1.6	0.082	lb/MMBtu	7.6	33.5	4.90E-07	lb/MMBtu	4.5E-05	2.0E-04	0.03	0.13	1.80E-07	lb/MMBtu	1.7E-05	7.3E-05	1.18E-08	lb/MMBtu	1.1E-06	4.8E-06
SD	F-7	14.8	MMBtu/hr	129,957	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0980	lb/MMBtu	1.5	6.4	0.0069	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.2	5.4	4.90E-07	lb/MMBtu	7.3E-06	3.2E-05	0.00	0.02	1.80E-07	lb/MMBtu	2.7E-06	1.2E-05	1.18E-08	lb/MMBtu	1.7E-07	7.6E-07
4UF																																										
Oth	F-1	34.5	MMBtu/hr	302,140	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.4	14.8	0.0075	lb/MMBtu	0.3	1.1	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.8	12.4	4.90E-07	lb/MMBtu	1.7E-05	7.4E-05	0.01	0.05	1.80E-07	lb/MMBtu	6.2E-06	2.7E-05	1.18E-08	lb/MMBtu	4.1E-07	1.8E-06
Oth	F-8A	74.1	MMBtu/hr	649,097	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.2745	lb/MMBtu	20.3	89.1	0.0075	lb/MMBtu	0.6	2.4	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.3	1.3	0.082	lb/MMBtu	6.1	26.7	4.90E-07	lb/MMBtu	3.6E-05	1.6E-04	0.03	0.11	1.80E-07	lb/MMBtu	1.3E-05	5.8E-05	1.18E-08	lb/MMBtu	8.7E-07	3.8E-06
Oth	F-8B	70.6	MMBtu/hr	618,527	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.2745	lb/MMBtu	19.4	84.9	0.0075	lb/MMBtu	0.5	2.3	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.3	1.2	0.082	lb/MMBtu	5.8	25.5	4.90E-07	lb/MMBtu	3.5E-05	1.5E-04	0.02	0.11	1.80E-07	lb/MMBtu	1.3E-05	5.6E-05	1.18E-08	lb/MMBtu	8.3E-07	3.6E-06
Oth	F-2	187.3	MMBtu/hr	1,640,317	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.4	0.1863	lb/MMBtu	34.9	152.8	0.0075	lb/MMBtu	1.4	6.1	0.0019	lb/MMBtu	0.3	1.5	0.0040	lb/MMBtu	0.7	3.3	0.082	lb/MMBtu	15.4	67.5	4.90E-07	lb/MMBtu	9.2E-05	4.0E-04	0.06	0.28	1.80E-07	lb/MMBtu	3.4E-05	1.5E-04	1.18E-08	lb/MMBtu	2.2E-06	9.6E-06
Oth	F-3	162.7	MMBtu/hr	1,425,543	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.8	0.2745	lb/MMBtu	44.7	195.7	0.0075	lb/MMBtu	1.2	5.3	0.0019	lb/MMBtu	0.3	1.3	0.0040	lb/MMBtu	0.7	2.9	0.082	lb/MMBtu	13.4	58.7	4.90E-07	lb/MMBtu	8.0E-05	3.5E-04	0.06	0.24	1.80E-07	lb/MMBtu	2.9E-05	1.3E-04	1.18E-08	lb/MMBtu	1.9E-06	8.4E-06
Oth	F-4	87.3	MMBtu/hr	764,368	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.1	0.2745	lb/MMBtu	24.0	104.9	0.0075	lb/MMBtu	0.7	2.9	0.0019	lb/MMBtu	0.2	0.7	0.0040	lb/MMBtu	0.3	1.5	0.082	lb/MMBtu	7.2	31.5	4.90E-07	lb/MMBtu	4.3E-05	1.9E-04	0.03	0.13	1.80E-07	lb/MMBtu	1.6E-05	6.9E-05	1.18E-08	lb/MMBtu	1.0E-06	4.5E-06
Oth	F-5	47.0	MMBtu/hr	411,990	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0980	lb/MMBtu	4.6	20.2	0.0075	lb/MMBtu	0.4	1.5	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.9	17.0	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.02	0.07	1.80E-07	lb/MMBtu	8.5E-06	3.7E-05	1.18E-08	lb/MMBtu	5.5E-07	2.4E-06
Oth	F-6	29.0	MMBtu/hr	254,070	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	2.8	12.5	0.0075	lb/MMBtu	0.2	1.0	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.4	10.5	4.90E-07	lb/MMBtu	1.4E-05	6.2E-05	0.01	0.04	1.80E-07	lb/MMBtu	5.2E-06	2.3E-05	1.18E-08	lb/MMBtu	3.4E-07	1.5E-06
Oth	F-7	32.1	MMBtu/hr	280,851	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.1	13.8	0.0075	lb/MMBtu	0.2	1.1	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.6	11.6	4.90E-07	lb/MMBtu	1.6E-05	6.9E-05	0.01	0.05	1.80E-07	lb/MMBtu	5.8E-06	2.5E-05	1.18E-08	lb/MMBtu	3.8E-07	1.7E-06
ARU																																										
Oth	F-200A	149.8	MMBtu/hr	1,312,684	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.2745	lb/MMBtu	41.1	180.2	0.0200	lb/MMBtu	3.0	13.1	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.6	0.082	lb/MMBtu	12.3	54.1	4.90E-07	lb/MMBtu	7.3E-05	3.2E-04	0.14	0.60	1.80E-07	lb/MMBtu	2.7E-05	1.2E-04	1.18E-08	lb/MMBtu	1.8E-06	7.7E-06
Oth	F-200B	147.0	MMBtu/hr	1,287,827	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.2745	lb/MMBtu	40.4	176.8	0.0200	lb/MMBtu	2.9	12.9	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.6	0.082	lb/MMBtu	12.1	53.0	4.90E-07	lb/MMBtu	7.2E-05	3.2E-04	0.13	0.59	1.80E-07	lb/MMBtu	2.6E-05	1.2E-04	1.18E-08	lb/MMBtu	1.7E-06	7.6E-06
BOU																																										
Mod	F-401	7.6	MMBtu/hr	66,485	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.2	0.0980	lb/MMBtu	0.7	3.3	0.0075	lb/MMBtu	0.1	0.2	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.1	0.082	lb/MMBtu	0.6	2.7	4.90E-07	lb/MMBtu	3.7E-06	1.6E-05	0.00	0.01	1.80E-07	lb/MMBtu	1.4E-06	6.0E-06	1.18E-08	lb/MMBtu	8.9E-08	3.9E-07
CFHU																																										
Oth	F-801A	9.2	MMBtu/hr	80,848	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.2	0.0490	lb/MMBtu	0.5	2.0	0.0094	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.8	3.3	4.90E-07	lb/MMBtu	4.5E-06	2.0E-05	0.00	0.02	1.80E-07	lb/MMBtu	1.7E-06	7.3E-06	1.18E-08	lb/MMBtu	1.1E-07	4.8E-07
Oth	F-801B	9.1	MMBtu/hr	79,550	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.2	0.0490	lb/MMBtu	0.4	1.9	0.0094	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.7	3.3	4.90E-07	lb/MMBtu	4.4E-06	1.9E-05	0.00	0.02	1.80E-07	lb/MMBtu	1.6E-06	7.2E-06	1.18E-08	lb/MMBtu	1.1E-07	4.7E-07
Oth	F-801C	0.5	MMBtu/hr	4,160	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.0360	lb/MMBtu	0.0	0.1	0.0094	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0040	lb/MMBtu	0.0	0.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	2.3E-07	1.0E-06	0.00	0.00	1.80E-07	lb/MMBtu	8.5E-08	3.7E-07	1.18E-08	lb/MMBtu	5.6E-09	2.4E-08
CRU																																										
Oth	F-101	23.6	MMBtu/hr	206,634	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0800	lb/MMBtu	1.9	8.3	0.0069	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.1	0.4	0.082	lb/MMBtu	1.9	8.5	4.90E-07	lb/MMBtu	1.2E-05	5.1E-05	0.01	0.03	1.80E-07	lb/MMBtu	4.2E-06	1.9E-05	1.18E-08	lb/MMBtu	2.8E-07	1.2E-06
Oth	F-102	17.0	MMBtu/hr	148,517	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0800	lb/MMBtu	1.4	5.9	0.0069	lb/MMBtu	0.1	0.5	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.4	6.1	4.90E-07	lb/MMBtu	8.3E-06	3.6E-05	0.01	0.02	1.80E-07	lb/MMBtu	3.1E-06	1.3E-05	1.18E-08	lb/MMBtu	2.0E-07	8.7E-07
DDU																																										
Oth	WB-301	33.5	MMBtu/hr	293,608	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0346	lb/MMBtu	1.2	5.1	0.0200	lb/MMBtu	0.7	2.9	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.040	lb/MMBtu	1.3	5.9	4.90E-07	lb/MMBtu	1.6E-05	7.2E-05	0.03	0.13	1.80E-07	lb/MMBtu	6.0E-06	2.6E-05	1.18E-08	lb/MMBtu	3.9E-07	1.7E-06
Oth	WB-302	52.9	MMBtu/hr	463,738	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.3	0.0300	lb/MMBtu	1.6	7.0	0.0200	lb/MMBtu	1.1	4.6	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.9	0.040	lb/MMBtu	2.1	9.3	4.90E-07	lb/MMBtu	2.6E-05	1.1E-04	0.05	0.21	1.80E-07	lb/MMBtu	9.5E-06	4.2E-05	1.18E-08	lb/MMBtu	6.2E-07	2.7E-06
ISOM																																										
Mod	H-1	140.2	MMBtu/hr	1,228,568	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.3	0.2745	lb/MMBtu	38.5	168.6	0.0200	lb/MMBtu	2.8	12.3	0.0019	lb/MMBtu	0.3	1.1	0.0040	lb/MMBtu	0.6	2.5	0.082	lb/MMBtu	11.5	50.6	4.90E-07	lb/MMBtu	6.9E-05	3.0E-04	0.13	0.56	1.80E-07	lb/MMBtu	2.5E-05	1.1E-04	1.18E-08	lb/MMBtu	1.6E-06	7.2E-06
HU																																										
Oth	B-501	145.5	MMBtu/hr	1,274,480	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.4	0.0675	lb/MMBtu	9.8	43.0	0.0650	lb/MMBtu	9.5	41.4	0.0019	lb/MMBtu	0.3	1.2	0.0075	lb/MMBtu	1.1	4.7	0.02	lb/MMBtu	2.9	12.7	4.90E-07	lb/MMBtu	7.1E-05	3.1E-04	0.43	1.90	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.5E-06
Utilities																																										
1SPS																																										
SD	Boiler 3	64.4	MMBtu/hr	563,952	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.5	0.1570	lb/MMBtu	10.1	44.3	0.0200	lb/MMBtu	1.3	5.6	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.5	2.1	0.049	lb/MMBtu	3.2	13.8	4.90E-07	lb/MMBtu	3.2E-05	1.4E-04	0.06	0.26	1.80E-07	lb/MMBtu	1.2E-05	5.1E-05	1.18E-08	lb/MMBtu	7.6E-07	3.3E-06
SD	Boiler 4	44.3	MMBtu/hr	387,967	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.1570	lb/MMBtu	7.0	30.5	0.0200	lb/MMBtu	0.9	3.9	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.3	1.4	0.049	lb/MMBtu	2.2	9.5	4.90E-07	lb/MMBtu	2.2E-05	9.5E-05	0.04	0.18	1.80E-07	lb/MMBtu	8.0E-06	3.5E-05	1.18E-08	lb/MMBtu	5.2E-07	2.3E-06
SD	Boiler 5	99.9	MMBtu/hr	874,982	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.4	0.0930	lb/MMBtu	9.3	40.7	0.0200	lb/MMBtu	2.0	8.7	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.7	3.3	0.248	lb/MMBtu	24.8	108.5	4.90E-07	lb/MMBtu	4.9E-05	2.1E-04	0.09	0.40	1.80E-07	lb/MMBtu	1.8E-05	7.9E-05	1.18E-08	lb/MMBtu	1.2E-06	5.1E-06
SD	Boiler 6	45.0	MMBtu/hr	394,009	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.1	0.0930	lb/MMBtu	4.2	18.3	0.0200	lb/MMBtu	0.9	3.9	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.3	1.5	0.248	lb/MMBtu	11.2	48.9	4.90E-07	lb/MMBtu	2.2E-05	9.7E-05	0.04	0.18	1.80E-07	lb/MMBtu	8.1E-06	3.5E-05	1.18E-08	lb/MMBtu	5.3E-07	2.3E-06
SD	Boiler 7	68.3	MMBtu/hr	598,463	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.6	0.0930	lb/MMBtu	6.4	27.8	0.0200	lb/MMBtu	1.4	6.0	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.5	2.2	0.248	lb/MMBtu	16.9	74.2	4.90E-07	lb/MMBtu	3.3E-05	1.5E-04	0.06	0.27	1.80E-07	lb/MMBtu	1.2E-05	5.4E-05	1.18E-08	lb/MMBtu	8.0E-07	3.5E-06
Lakefront																																										
SD	FBI	17	MMGal/yr	86,369	tons feed	0.0305	lb/unit

Table C.17. 2004 Combustion Emissions

Process Heaters and Boilers

Code	Process Unit	Usage			VOC EF	VOC Unit	VOC lb/hr[1]	VOC tpy	NO_x EF	NO_x Unit	NO_x lb/hr[1]	NO_x tpy	SO_2 EF	SO_2 Unit	SO_2 lb/hr[1]	SO_2 tpy	PM (Filterable) EF	PM (Filterable) Unit	PM (Filterable) lb/hr[1]	PM (Filterable) tpy	$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[2] EF	$PM_{10}/PM_{2.5}$ Unit	$PM_{10}/PM_{2.5}$ lb/hr[1]	$PM_{10}/PM_{2.5}$ tpy	CO EF	CO Unit	CO lb/hr[1]	CO tpy	Pb EF	Pb Unit	Pb lb/hr[1]	Pb tpy	H_2SO_4 Mist lb/hr[1]	H_2SO_4 Mist tpy	Hg EF	Hg Unit	Hg lb/hr[1]	Hg tpy	Be EF	Be Unit	Be lb/hr[1]	Be tpy
Crude and Coking																																									
11A PS																																									
Oth	H-1X	145.6	MMBtu/hr	1,275,256	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.4	0.1660	lb/MMBtu	24.2	105.8	0.0237	lb/MMBtu	3.4	15.1	0.0019	lb/MMBtu	0.3	1.2	0.0075	lb/MMBtu	1.1	4.8	0.082	lb/MMBtu	12.0	52.5	4.90E-07	lb/MMBtu	7.1E-05	3.1E-04	0.16	0.69	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.5E-06
Oth	H-2	18.5	MMBtu/hr	162,191	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0980	lb/MMBtu	1.8	8.0	0.0237	lb/MMBtu	0.4	1.9	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	1.5	6.7	4.90E-07	lb/MMBtu	9.1E-06	4.0E-05	0.02	0.09	1.80E-07	lb/MMBtu	3.3E-06	1.5E-05	1.18E-08	lb/MMBtu	2.2E-07	9.5E-07
Oth	H-3	44.4	MMBtu/hr	389,180	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.4	19.1	0.0237	lb/MMBtu	1.1	4.6	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.3	1.4	0.082	lb/MMBtu	3.7	16.0	4.90E-07	lb/MMBtu	2.2E-05	9.5E-05	0.05	0.21	1.80E-07	lb/MMBtu	8.0E-06	3.5E-05	1.18E-08	lb/MMBtu	5.2E-07	2.3E-06
11C PS																																									
Cont	H-200	107.1	MMBtu/hr	937,919	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.5	0.2745	lb/MMBtu	29.4	128.7	0.0237	lb/MMBtu	2.5	11.1	0.0019	lb/MMBtu	0.2	0.9	0.0075	lb/MMBtu	0.8	3.5	0.082	lb/MMBtu	8.8	38.6	4.90E-07	lb/MMBtu	5.2E-05	2.3E-04	0.12	0.51	1.80E-07	lb/MMBtu	1.9E-05	8.4E-05	1.18E-08	lb/MMBtu	1.3E-06	5.5E-06
Oth	H-300	74.3	MMBtu/hr	651,022	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.1373	lb/MMBtu	10.2	44.7	0.0237	lb/MMBtu	1.8	7.7	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.6	2.4	0.082	lb/MMBtu	6.1	26.8	4.90E-07	lb/MMBtu	3.6E-05	1.6E-04	0.08	0.35	1.80E-07	lb/MMBtu	1.3E-05	5.9E-05	1.18E-08	lb/MMBtu	8.7E-07	3.8E-06
Coker																																									
SD	H-101	34.6	MMBtu/hr	303,049	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.4	14.9	0.0237	lb/MMBtu	0.8	3.6	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.8	12.5	4.90E-07	lb/MMBtu	1.7E-05	7.4E-05	0.04	0.16	1.80E-07	lb/MMBtu	6.2E-06	2.7E-05	1.18E-08	lb/MMBtu	4.1E-07	1.8E-06
SD	H-102	32.1	MMBtu/hr	281,600	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.2	13.8	0.0237	lb/MMBtu	0.8	3.3	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.6	11.6	4.90E-07	lb/MMBtu	1.6E-05	6.9E-05	0.03	0.15	1.80E-07	lb/MMBtu	5.8E-06	2.5E-05	1.18E-08	lb/MMBtu	3.8E-07	1.7E-06
SD	H-103	31.1	MMBtu/hr	272,646	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	3.1	13.4	0.0237	lb/MMBtu	0.7	3.2	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.6	11.2	4.90E-07	lb/MMBtu	1.5E-05	6.7E-05	0.03	0.15	1.80E-07	lb/MMBtu	5.6E-06	2.5E-05	1.18E-08	lb/MMBtu	3.7E-07	1.6E-06
SD	H-104	33.3	MMBtu/hr	291,574	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.3	14.3	0.0237	lb/MMBtu	0.8	3.5	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.7	12.0	4.90E-07	lb/MMBtu	1.6E-05	7.1E-05	0.04	0.16	1.80E-07	lb/MMBtu	6.0E-06	2.6E-05	1.18E-08	lb/MMBtu	3.9E-07	1.7E-06
12PS																																									
SD	H-1AN	83.6	MMBtu/hr	732,363	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.0	0.2745	lb/MMBtu	22.9	100.5	0.0237	lb/MMBtu	2.0	8.7	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.6	2.7	0.082	lb/MMBtu	6.9	30.2	4.90E-07	lb/MMBtu	4.1E-05	1.8E-04	0.09	0.40	1.80E-07	lb/MMBtu	1.5E-05	6.6E-05	1.18E-08	lb/MMBtu	9.8E-07	4.3E-06
SD	H-1AS	58.6	MMBtu/hr	513,370	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.4	0.2745	lb/MMBtu	16.1	70.5	0.0237	lb/MMBtu	1.4	6.1	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.4	1.9	0.082	lb/MMBtu	4.8	21.1	4.90E-07	lb/MMBtu	2.9E-05	1.3E-04	0.06	0.28	1.80E-07	lb/MMBtu	1.1E-05	4.6E-05	1.18E-08	lb/MMBtu	6.9E-07	3.0E-06
SD	H-1B	166.5	MMBtu/hr	1,458,600	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.9	0.2745	lb/MMBtu	45.7	200.2	0.0237	lb/MMBtu	3.9	17.3	0.0019	lb/MMBtu	0.3	1.4	0.0075	lb/MMBtu	1.2	5.4	0.082	lb/MMBtu	13.7	60.1	4.90E-07	lb/MMBtu	8.2E-05	3.6E-04	0.18	0.79	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.18E-08	lb/MMBtu	2.0E-06	8.6E-06
SD	H-2	120.4	MMBtu/hr	1,054,784	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.8	0.0360	lb/MMBtu	4.3	19.0	0.0237	lb/MMBtu	2.8	12.5	0.0019	lb/MMBtu	0.2	1.0	0.0075	lb/MMBtu	0.9	3.9	0.0001	lb/MMBtu	0.0	0.1	4.90E-07	lb/MMBtu	5.9E-05	2.6E-04	0.13	0.57	1.80E-07	lb/MMBtu	2.2E-05	9.5E-05	1.18E-08	lb/MMBtu	1.4E-06	6.2E-06
SD	H-1CN	67.2	MMBtu/hr	588,736	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.6	0.0980	lb/MMBtu	6.6	28.9	0.0237	lb/MMBtu	1.6	7.0	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.3	1.2	0.082	lb/MMBtu	5.5	24.2	4.90E-07	lb/MMBtu	3.3E-05	1.4E-04	0.07	0.32	1.80E-07	lb/MMBtu	1.2E-05	5.3E-05	1.18E-08	lb/MMBtu	7.9E-07	3.5E-06
SD	H-1CX	205.0	MMBtu/hr	1,795,720	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.8	0.0990	lb/MMBtu	20.3	88.9	0.0237	lb/MMBtu	4.9	21.2	0.0019	lb/MMBtu	0.4	1.7	0.0040	lb/MMBtu	0.8	3.6	0.082	lb/MMBtu	16.9	73.9	4.90E-07	lb/MMBtu	1.0E-04	4.4E-04	0.22	0.98	1.80E-07	lb/MMBtu	3.7E-05	1.6E-04	1.18E-08	lb/MMBtu	2.4E-06	1.1E-05
Hydroprocessing																																									
3UF																																									
SD	H-1	87.3	MMBtu/hr	764,513	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.1	0.2745	lb/MMBtu	24.0	104.9	0.0061	lb/MMBtu	0.5	2.3	0.0019	lb/MMBtu	0.2	0.7	0.0040	lb/MMBtu	0.3	1.5	0.082	lb/MMBtu	7.2	31.5	4.90E-07	lb/MMBtu	4.3E-05	1.9E-04	0.02	0.11	1.80E-07	lb/MMBtu	1.6E-05	6.9E-05	1.18E-08	lb/MMBtu	1.0E-06	4.5E-06
SD	H-2	110.5	MMBtu/hr	968,099	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.6	0.2745	lb/MMBtu	30.3	132.9	0.0061	lb/MMBtu	0.7	3.0	0.0019	lb/MMBtu	0.2	0.9	0.0040	lb/MMBtu	0.4	1.9	0.082	lb/MMBtu	9.1	39.9	4.90E-07	lb/MMBtu	5.4E-05	2.4E-04	0.03	0.14	1.80E-07	lb/MMBtu	2.0E-05	8.7E-05	1.18E-08	lb/MMBtu	1.3E-06	5.7E-06
SD	F-7	14.2	MMBtu/hr	124,422	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0980	lb/MMBtu	1.4	6.1	0.0061	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.2	0.082	lb/MMBtu	1.2	5.1	4.90E-07	lb/MMBtu	7.0E-06	3.0E-05	0.00	0.02	1.80E-07	lb/MMBtu	2.6E-06	1.1E-05	1.18E-08	lb/MMBtu	1.7E-07	7.3E-07
4UF																																									
Oth	F-1	37.8	MMBtu/hr	331,540	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.7	16.3	0.0059	lb/MMBtu	0.2	1.0	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.1	13.7	4.90E-07	lb/MMBtu	1.9E-05	8.1E-05	0.01	0.05	1.80E-07	lb/MMBtu	6.8E-06	3.0E-05	1.18E-08	lb/MMBtu	4.5E-07	2.0E-06
Oth	F-8A	67.2	MMBtu/hr	588,482	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.6	0.2745	lb/MMBtu	18.4	80.8	0.0059	lb/MMBtu	0.4	1.7	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.3	1.2	0.082	lb/MMBtu	5.5	24.2	4.90E-07	lb/MMBtu	3.3E-05	1.4E-04	0.02	0.08	1.80E-07	lb/MMBtu	1.2E-05	5.3E-05	1.18E-08	lb/MMBtu	7.9E-07	3.5E-06
Oth	F-8B	63.5	MMBtu/hr	556,179	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.5	0.2745	lb/MMBtu	17.4	76.3	0.0059	lb/MMBtu	0.4	1.7	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.3	1.1	0.082	lb/MMBtu	5.2	22.9	4.90E-07	lb/MMBtu	3.1E-05	1.4E-04	0.02	0.08	1.80E-07	lb/MMBtu	1.1E-05	5.0E-05	1.18E-08	lb/MMBtu	7.5E-07	3.3E-06
Oth	F-2	190.7	MMBtu/hr	1,670,948	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.5	0.1863	lb/MMBtu	35.5	155.6	0.0059	lb/MMBtu	1.1	5.0	0.0019	lb/MMBtu	0.4	1.6	0.0040	lb/MMBtu	0.8	3.3	0.082	lb/MMBtu	15.7	68.8	4.90E-07	lb/MMBtu	9.4E-05	4.1E-04	0.05	0.23	1.80E-07	lb/MMBtu	3.4E-05	1.5E-04	1.18E-08	lb/MMBtu	2.2E-06	9.8E-06
Oth	F-3	165.3	MMBtu/hr	1,448,451	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.9	0.2745	lb/MMBtu	45.4	198.8	0.0059	lb/MMBtu	1.0	4.3	0.0019	lb/MMBtu	0.3	1.3	0.0040	lb/MMBtu	0.7	2.9	0.082	lb/MMBtu	13.6	59.6	4.90E-07	lb/MMBtu	8.1E-05	3.6E-04	0.05	0.20	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.18E-08	lb/MMBtu	1.9E-06	8.5E-06
Oth	F-4	94.2	MMBtu/hr	825,437	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.2	0.2745	lb/MMBtu	25.9	113.3	0.0059	lb/MMBtu	0.6	2.4	0.0019	lb/MMBtu	0.2	0.8	0.0040	lb/MMBtu	0.4	1.7	0.082	lb/MMBtu	7.8	34.0	4.90E-07	lb/MMBtu	4.6E-05	2.0E-04	0.03	0.11	1.80E-07	lb/MMBtu	1.7E-05	7.4E-05	1.18E-08	lb/MMBtu	1.1E-06	4.9E-06
Oth	F-5	47.7	MMBtu/hr	417,621	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0980	lb/MMBtu	4.7	20.5	0.0059	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.9	17.2	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.01	0.06	1.80E-07	lb/MMBtu	8.6E-06	3.8E-05	1.18E-08	lb/MMBtu	5.6E-07	2.5E-06
Oth	F-6	35.8	MMBtu/hr	313,608	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.5	15.4	0.0059	lb/MMBtu	0.2	0.9	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.9	12.9	4.90E-07	lb/MMBtu	1.6E-05	7.0E-05	0.01	0.04	1.80E-07	lb/MMBtu	6.4E-06	2.8E-05	1.18E-08	lb/MMBtu	4.2E-07	1.8E-06
Oth	F-7	32.4	MMBtu/hr	284,134	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.2	13.9	0.0059	lb/MMBtu	0.2	0.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.7	11.7	4.90E-07	lb/MMBtu	1.6E-05	7.0E-05	0.01	0.04	1.80E-07	lb/MMBtu	5.8E-06	2.6E-05	1.18E-08	lb/MMBtu	3.8E-07	1.7E-06
ARU																																									
Oth	F-200A	191.3	MMBtu/hr	1,675,689	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.5	0.2745	lb/MMBtu	52.5	230.0	0.0237	lb/MMBtu	4.5	19.8	0.0019	lb/MMBtu	0.4	1.6	0.0040	lb/MMBtu	0.8	3.4	0.082	lb/MMBtu	15.8	69.0	4.90E-07	lb/MMBtu	9.4E-05	4.1E-04	0.21	0.91	1.80E-07	lb/MMBtu	3.4E-05	1.5E-04	1.18E-08	lb/MMBtu	2.3E-06	9.9E-06
Oth	F-200B	179.7	MMBtu/hr	1,574,497	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.2	0.2745	lb/MMBtu	49.3	216.1	0.0237	lb/MMBtu	4.3	18.6	0.0019	lb/MMBtu	0.3	1.5	0.0040	lb/MMBtu	0.7	3.1	0.082	lb/MMBtu	14.8	64.8	4.90E-07	lb/MMBtu	8.8E-05	3.9E-04	0.20	0.86	1.80E-07	lb/MMBtu	3.2E-05	1.4E-04	1.18E-08	lb/MMBtu	2.1E-06	9.3E-06
BOU																																									
Mod	F-401	15.0	MMBtu/hr	131,318	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0980	lb/MMBtu	1.5	6.4	0.0059	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.2	5.4	4.90E-07	lb/MMBtu	7.3E-06	3.2E-05	0.00	0.02	1.80E-07	lb/MMBtu	2.7E-06	1.2E-05	1.18E-08	lb/MMBtu	1.8E-07	7.7E-07
CFHU																																									
Oth	F-801A	10.8	MMBtu/hr	94,183	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0490	lb/MMBtu	0.5	2.3	0.0078	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.9	3.9	4.90E-07	lb/MMBtu	5.3E-06	2.3E-05	0.00	0.02	1.80E-07	lb/MMBtu	1.9E-06	8.5E-06	1.18E-08	lb/MMBtu	1.3E-07	5.5E-07
Oth	F-801B	11.3	MMBtu/hr	98,575	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0490	lb/MMBtu	0.6	2.4	0.0078	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.9	4.1	4.90E-07	lb/MMBtu	5.5E-06	2.4E-05	0.00	0.02	1.80E-07	lb/MMBtu	2.0E-06	8.9E-06	1.18E-08	lb/MMBtu	1.3E-07	5.8E-07
Oth	F-801C	0.1	MMBtu/hr	1,131	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.0360	lb/MMBtu	0.0	0.0	0.0078	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0040	lb/MMBtu	0.0	0.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	6.3E-08	2.8E-07	0.00	0.00	1.80E-07	lb/MMBtu	2.3E-08	1.0E-07	1.18E-08	lb/MMBtu	1.5E-09	6.7E-09
CRU																																									
Oth	F-101	18.4	MMBtu/hr	160,857	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0800	lb/MMBtu	1.5	6.4	0.0061	lb/MMBtu	0.1	0.5	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.5	6.6	4.90E-07	lb/MMBtu	9.0E-06	3.9E-05	0.01	0.02	1.80E-07	lb/MMBtu	3.3E-06	1.4E-05	1.18E-08	lb/MMBtu	2.2E-07	9.5E-07
Oth	F-102	26.1	MMBtu/hr	228,260	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0800	lb/MMBtu	2.1	9.1	0.0061	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.1	9.4	4.90E-07	lb/MMBtu	1.3E-05	5.6E-05	0.01	0.03	1.80E-07	lb/MMBtu	4.7E-06	2.1E-05	1.18E-08	lb/MMBtu	3.1E-07	1.3E-06
DDU																																									
Oth	WB-301	39.3	MMBtu/hr	344,060	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0346	lb/MMBtu	1.4	6.0	0.0237	lb/MMBtu	0.9	4.1	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.040	lb/MMBtu	1.6	7.1	4.90E-07	lb/MMBtu	1.9E-05	8.4E-05	0.04	0.19	1.80E-07	lb/MMBtu	7.1E-06	3.1E-05	1.18E-08	lb/MMBtu	4.6E-07	2.0E-06
Oth	WB-302	47.4	MMBtu/hr	415,593	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0300	lb/MMBtu	1.4	6.2	0.0237	lb/MMBtu	1.1	4.9	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.040	lb/MMBtu	1.9	8.3	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.05	0.23	1.80E-07	lb/MMBtu	8.5E-06	3.7E-05	1.18E-08	lb/MMBtu	5.6E-07	2.4E-06
ISOM																																									
Mod	H-1	130.2	MMBtu/hr	1,140,305	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.1	0.2745	lb/MMBtu	35.7	156.5	0.0237	lb/MMBtu	3.1	13.5	0.0019	lb/MMBtu	0.2	1.1	0.0040	lb/MMBtu	0.5	2.3	0.082	lb/MMBtu	10.7	47.0	4.90E-07	lb/MMBtu	6.4E-05	2.8E-04	0.14	0.62	1.80E-07	lb/MMBtu	2.3E-05	1.0E-04	1.18E-08	lb/MMBtu	1.5E-06	6.7E-06
HU																																									
Oth	B-501	192.2	MMBtu/hr	1,683,372	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.5	0.0675	lb/MMBtu	13.0	56.8	0.0771	lb/MMBtu	14.8	64.9	0.0019	lb/MMBtu	0.4	1.6	0.0075	lb/MMBtu	1.4	6.3	0.02	lb/MMBtu	3.8	16.8	4.90E-07	lb/MMBtu	9.4E-05	4.1E-04	0.68	2.98	1.80E-07	lb/MMBtu	3.5E-05	1.5E-04	1.18E-08	lb/MMBtu	2.3E-06	9.9E-06
Utilities																																									
1SPS																																									
SD	Boiler 3	52.9	MMBtu/hr	463,525	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.1570	lb/MMBtu	8.3	36.4	0.0237	lb/MMBtu	1.3	5.5	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.4	1.7	0.049	lb/MMBtu	2.6	11.4	4.90E-07	lb/MMBtu	2.6E-05	1.1E-04	0.06	0.25	1.80E-07	lb/MMBtu	9.5E-06	4.2E-05	1.18E-08	lb/MMBtu	6.2E-07	2.7E-06
SD	Boiler 4	75.4	MMBtu/hr	660,481	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.1570	lb/MMBtu	11.8	51.8	0.0237	lb/MMBtu	1.8	7.8	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.6	2.5	0.049	lb/MMBtu	3.7	16.2	4.90E-07	lb/MMBtu	3.7E-05	1.6E-04	0.08	0.36	1.80E-07	lb/MMBtu	1.4E-05	5.9E-05	1.18E-08	lb/MMBtu	8.9E-07	3.9E-06
SD	Boiler 5	69.9	MMBtu/hr	612,637	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.0930	lb/MMBtu	6.5	28.5	0.0237	lb/MMBtu	1.7	7.2	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.5	2.3	0.248	lb/MMBtu	17.3	76.0	4.90E-07	lb/MMBtu	3.4E-05	1.5E-04	0.08	0.33	1.80E-07	lb/MMBtu	1.3E-05	5.5E-05	1.18E-08	lb/MMBtu	8.2E-07	3.6E-06
SD	Boiler 6	49.0	MMBtu/hr	429,528	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.0930	lb/MMBtu	4.6	20.0	0.0237	lb/MMBtu	1.2	5.1	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.4	1.6	0.248	lb/MMBtu	12.2	53.3	4.90E-07	lb/MMBtu	2.4E-05	1.1E-04	0.05	0.23	1.80E-07	lb/MMBtu	8.8E-06	3.9E-05	1.18E-08	lb/MMBtu	5.8E-07	2.5E-06
SD	Boiler 7	114.4	MMBtu/hr	1,002,405	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.7	0.0930	lb/MMBtu	10.6	46.6	0.0237	lb/MMBtu	2.7	11.9	0.0019	lb/MMBtu	0.2	0.9	0.0075	lb/MMBtu	0.9	3.7	0.248	lb/MMBtu	28.4	124.3	4.90E-07	lb/MMBtu	5.6E-05	2.5E-04	0.12	0.54	1.80E-07	lb/MMBtu	2.1E-05	9.0E-05	1.18E-08	lb/MMBtu	1.3E-06	5.9E-06
Lakefront																																									
SD	FBI	18	MMGal/yr	89.905	tons feed	0.0305	lb/unit feed	0.3	1.4	4.

Table C.18. Baseline FBI Beryllium Emissions

Year	Feed		Be Emission Factor		Be Emissions (lb)
2002	17.26	MMGal/yr	8.22E-06	lb/Mgal	0.14
2003	17.26	MMGal/yr	5.73E-06	lb/Mgal	0.10
2004	17.97	MMGal/yr	8.22E-06	lb/Mgal	0.15
2005	12.93	MMGal/yr	8.22E-06	lb/Mgal	0.11
2006	7.63	MMGal/yr	8.22E-06	lb/Mgal	0.06

Baseline Average	Be Emissions (tpy)
2002-2003	6.02E-05
2003-2004	6.16E-05
2004-2005	6.35E-05
2005-2006	4.22E-05

Table C.19. Project Sulfur Recovery Complex Emissions

Process Unit	Natural Gas Usage (MMBtu/hr)	VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
COT 1 and 2	144	0.0054	lb/MMBtu	0.8	3.4	0.08	lb/MMBtu	11.5	50.5	0.0006	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.3	1.2	0.0075	lb/MMBtu	1.1	4.7	4.90E-07	lb/MMBtu	7.06E-05	3.09E-04	0.004	0.02	1.80E-07	lb/MMBtu	2.59E-05	1.14E-04	1.18E-08	lb/MMBtu	1.69E-06	7.42E-06

Process Unit	Future SO_2 Conc. (PPM)	Exhaust Air Flow (scfh)	SO_2		H_2SO_4 Mist	
			lb/hr[1]	tpy	lb/hr[1]	tpy
COT 1 and 2	45	5,929,500	44.4	194.5	2.0	8.9

Process Unit	Future H_2S (lb-mol/hr)	Anticipated days/yr at operating rate	H_2S		Total Reduced Sulfur[3]	
			lb/hr[1]	tpy	lb/hr[1]	tpy
COT 1 and 2	0.06	365	2.0	8.9	2.0	8.9

Process Unit	CO Combustion Emissions				CO Process Emissions[2]	
	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy
COT 1 and 2	0.05	lb/MMBtu	7.2	31.5	5.4	23.5

Sulfur Loading Emissions**

	H_2S Conc.	H_2S Emitted		Total Reduced Sulfur[3]	
	ppm	lb/hr	tpy	lb/hr	tpy
Before Loading	10	1.2	5.3	1.2	5.3
After Loading	0	0.0	0.0	0.0	0.0
H_2S Emitted		1.2	5.3	1.2	5.3

[1] Hourly emission rate represents annual average hourly emissions.
[2] Total CO emissions from the COT 1 and 2 are estimated to be 55 ton/yr. Combustion emissions are calculated using vendor emission factors (See Table 1) and are based on the amount of natural gas combusted at the units. An additional amount of CO emissions is estimated based on CO2 inherent in the process gas fed to the SRU which may be emitted as additional CO emissions at the COTs.
[3] Emissions of Total Reduced Sulfur from the COTs and sulfur loading are assumed to be equal to emissions of H_2S.

* Each COT is capable of operating to accommodate the total SRU train loading of 1300 LTPD for the purpose of redundancy.
** Based on future capacity of 1300 LTPD sulfur production. Conservatively assumes that all H_2S present in sulfur is emitted during the loading process.
*** In the future, sulfur pits will be controlled and routed back to the SRU process, therefore there will be no H_2S emissions from the sulfur pits.

Table C.20. 1999 Sulfur Recovery Complex Emissions

Combustor Emissions

Process Unit	Natural Gas Usage (MMscf/yr)	VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				CO				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
SBS TGU	0.0	5.5	lb/MMscf	0.0	0.0	100	lb/MMscf	0.0	0.0	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.0	84	lb/MMscf	0.0	0.0	5.00E-04	lb/MMscf	0.0E+00	0.0E+00	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
Beavon-Stretford TGU	47.2	5.5	lb/MMscf	0.0	0.1	100	lb/MMscf	0.5	2.4	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.2	84	lb/MMscf	0.5	2.0	5.00E-04	lb/MMscf	2.7E-06	1.2E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
SRU Incinerator	108.6	5.5	lb/MMscf	0.1	0.3	100	lb/MMscf	1.2	5.4	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.4	84	lb/MMscf	1.0	4.6	5.00E-04	lb/MMscf	6.2E-06	2.7E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000

* The total flow to the Beavon-Stretford TGU in 1999 was 309,785.9 ton/yr based on data recorded by the BP Whiting PI data collection system.
Note the PM_{10} emission limit provided in the PM_{10} SIP is 0.110 lb/ton. Therefore, in 1999 the PM_{10} emissions were below this limit (359.0 lb PM_{10}/yr)/(309,785.9 ton/yr) = 0.0012 lb/ton.

SBS Process Emissions

Process Unit	Sulfur Flow (LTPD)	SBS Exhaust	CEMS Data SO_2 Conc.	SO_2[1] (lb/hr)	SO_2 (tpy)	H_2SO_4 Mist	
						lb/hr[1]	tpy
SBS TGU	0.0	0.0	0	0.0	0.0	0.00	0.00

Beavon Stretford Process Emissions

No. of Days Combusting	Actual Airflow MAscf/hr	SO_2[1] lb/hr**	SO_2 tpy	H_2SO_4 Mist		H_2S lb/hr	H_2S tpy	Total Reduced Sulfur lb/hr	Total Reduced Sulfur tpy
				lb/hr[1]	tpy				
81	1,866	7.7	7.5	0.36	0.35	0.6	2.6	12.6	55.4

** The SO_2 concentration is calculated based on average daily H_2S and TRS CEMS Data.

The Beavon Stretford combustor temperature ramps up if the H_2S concentration approaches 10 ppm. BP Whiting has estimated that approximately 30% of the TRS/H2S sulfur is converted to SO_2 after the combustion temperature ramps up.

[1] Hourly emission rate represents annual average hourly emissions.
**** Sulfur pit loading emissions have only been included for the H_2S/TRS baseline years of 2000-2001.

Table C.21. 2000 Sulfur Recovery Complex Emissions

Combustor Emissions

Process Unit	Natural Gas Usage (MMscf/yr)	VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				CO				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
SBS TGU	0.0	5.5	lb/MMscf	0.0	0.0	100	lb/MMscf	0.0	0.0	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.0	84	lb/MMscf	0.0	0.0	5.00E-04	lb/MMscf	0.0E+00	0.0E+00	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
Beavon-Stretford TGU	90.1	5.5	lb/MMscf	0.1	0.2	100	lb/MMscf	1.0	4.5	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.3	84	lb/MMscf	0.9	3.8	5.00E-04	lb/MMscf	5.1E-06	2.3E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
SRU Incinerator	114.0	5.5	lb/MMscf	0.1	0.3	100	lb/MMscf	1.3	5.7	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.4	84	lb/MMscf	1.1	4.8	5.00E-04	lb/MMscf	6.5E-06	2.9E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000

* The total flow to the Beavon-Stretford TGU in 2000 was 317,615.7 ton/yr based on data recorded by the BP Whiting PI data collection system.
Note the PM_{10} emission limit provided in the PM_{10} SIP is 0.110 lb/ton. Therefore, in 2000 the PM_{10} emissions were below this limit (684.6 lb PM_{10}/yr)/(317,615.7 ton/yr) = 0.002 lb/ton.

SBS Process Emissions

Process Unit	Sulfur Flow (LTPD)	SBS Exhaust	CEMS Data SO_2 Conc.	SO_2[1] (lb/hr)	SO_2 (tpy)	H_2SO_4 Mist	
						lb/hr[1]	tpy
SBS TGU	0.0	0.0	0	0.0	0.0	0.00	0.00

Beavon Stretford Process Emissions

No. of Days Combusting	Actual Airflow MAscf/hr	SO_2[1] lb/hr**	SO_2 tpy	H_2SO_4 Mist		H_2S lb/hr	H_2S tpy	Total Reduced Sulfur lb/hr	Total Reduced Sulfur tpy
				lb/hr[1]	tpy				
47	1,774	6.5	3.7	0.30	0.17	0.5	2.2	13.2	57.7

** The SO_2 concentration is calculated based on average daily H_2S and TRS CEMS Data.

The Beavon Stretford combustor temperature ramps up if the H_2S concentration approaches 10 ppm. BP Whiting has estimated that approximately 30% of the TRS/H2S sulfur is converted to SO_2 after the combustion temperature ramps up.

Sulfur Pit Emissions

Tank No.	Saturated Sulfur Conc. (ppm)	Average Sulfur Stored (LTPD)	Tank Capacity (LT)	Average Residence Time (days)	H_2S Emissions (lb/hr)	H_2S Emissions (ton/yr)	
TK-201	250	144.1	63.8	0.22	0.2	1.0	
TK-231	250	94.7	63.8	0.34	0.2	1.0	
TK-261	250	175.3	58.0	0.33	0.4	1.8	
TK-310	204.0	414.1	2400.0	4.35	3.7	16.4	

Sulfur Loading Emissions***

	H_2S Conc. (ppm)	Average Sulfur Stored (LTPD)	H_2S in sulfur (lb/hr)	H_2S in sulfur (ton/yr)	H_2S Emitted (lb/hr)	H_2S Emitted (ton/yr)	
Before Loading	250	414.1	9.7	42.5			
After Loading	200	414.1	7.8	34.0			
					1.9	8.5	

*** The difference in the amount of H_2S in the sulfur before and after loading is assumed to be emitted to atmosphere as part of the loading process.

[1] Hourly emission rate represents annual average hourly emissions.

**** Sulfur pit loading emissions have only been included for the H_2S/TRS baseline years of 2000-2001.

Table C.22. 2001 Sulfur Recovery Complex Emissions

Combustor Emissions

Process Unit	Natural Gas Usage (MMscf/yr)	VOC				NO_x				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				CO				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
SBS TGU	0.0	5.5	lb/MMscf	0.0	0.0	100	lb/MMscf	0.0	0.0	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.0	84	lb/MMscf	0.0	0.0	5.00E-04	lb/MMscf	0.0E+00	0.0E+00	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
Beavon-Stretford TGU	83.1	5.5	lb/MMscf	0.1	0.2	100	lb/MMscf	0.9	4.2	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.3	84	lb/MMscf	0.8	3.5	5.00E-04	lb/MMscf	4.7E-06	2.1E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
SRU Incinerator	123.3	5.5	lb/MMscf	0.1	0.3	100	lb/MMscf	1.4	6.2	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.5	84	lb/MMscf	1.2	5.2	5.00E-04	lb/MMscf	7.0E-06	3.1E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000

* The total flow to the Beavon-Stretford TGU in 2001 was 321,415.6 ton/yr based on data recorded by the BP Whiting PI data collection system.
Note the PM_{10} emission limit provided in the PM_{10} SIP is 0.110 lb/ton. Therefore, in 2001 the PM_{10} emissions were below this limit (631.9 lb PM_{10}/yr)/(321,415.6 ton/yr) = 0.0002 lb/ton.

SBS Process Emissions

Process Unit	Sulfur Flow (LTPD)	SBS Exhaust	CEMS Data SO_2 Conc.	SO_2[1] (lb/hr)	SO_2 (tpy)	H_2SO_4 Mist	
						lb/hr[1]	tpy
SBS TGU	0.0	0.0	0	0.0	0.0	0.00	0.00

Beavon Stretford Process Emissions

No. of Days Combusting	Actual Airflow MAscf/hr	SO_2[1] lb/hr**	SO_2 tpy	H_2SO_4 Mist		H_2S lb/hr	H_2S tpy	Total Reduced Sulfur lb/hr	Total Reduced Sulfur tpy
				lb/hr[1]	tpy				
74	1,885	7.1	6.3	0.33	0.29	0.5	2.3	15.3	67.2

** The SO_2 concentration is calculated based on average daily H_2S and TRS CEMS Data.

The Beavon Stretford combustor temperature ramps up if the H_2S concentration approaches 10 ppm. BP Whiting has estimated that approximately 30% of the TRS/H2S sulfur is converted to SO_2 after the combustion temperature ramps up.

Sulfur Pit Emissions

Tank No.	Saturated Sulfur Conc. (ppm)	Average Sulfur Stored (LTPD)	Tank Capacity (LT)	Average Residence Time (days)	H_2S Emissions (lb/hr)	H_2S Emissions (ton/yr)	
TK-201	250	120.3	63.8	0.27	0.2	1.0	
TK-231	250	123.3	63.8	0.26	0.2	1.0	
TK-261	250	159.2	58.0	0.36	0.4	1.8	
TK-310	202.9	402.8	2400.0	4.47	3.6	15.9	

Sulfur Loading Emissions***

	H_2S Conc. (ppm)	Average Sulfur Stored (LTPD)	H_2S in sulfur (lb/hr)	H_2S in sulfur (ton/yr)	H_2S Emitted (lb/hr)	H_2S Emitted (ton/yr)	
Before Loading	250	402.8	9.4	41.4			
After Loading	200	402.8	7.6	33.1			
					1.9	8.3	

*** The difference in the amount of H_2S in the sulfur before and after loading is assumed to be emitted to atmosphere as part of the loading process.
[1] Hourly emission rate represents annual average hourly emissions.
**** Sulfur pit loading emissions have only been included for the H_2S/TRS baseline years of 2000-2001.

Table C.23. 2002 Sulfur Recovery Complex Emissions

Combustor Emissions

Process Unit	Natural Gas Usage (MMscf/yr)	VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				CO				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
SBS TGU	78.9	5.5	lb/MMscf	0.0	0.2	100	lb/MMscf	0.9	3.9	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.3	84	lb/MMscf	0.8	3.3	5.00E-04	lb/MMscf	4.5E-06	2.0E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
Beavon-Stretford TGU	48.4	5.5	lb/MMscf	0.0	0.1	100	lb/MMscf	0.6	2.4	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.2	84	lb/MMscf	0.5	2.0	5.00E-04	lb/MMscf	2.8E-06	1.2E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
SRU Incinerator	89.7	5.5	lb/MMscf	0.1	0.2	100	lb/MMscf	1.0	4.5	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.3	84	lb/MMscf	0.9	3.8	5.00E-04	lb/MMscf	5.1E-06	2.2E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000

* The total flow to the Beavon-Stretford TGU in 2002 was 281,855.0 ton/yr based on data recorded by the BP Whiting PI data collection system.
Note the PM_{10} emission limit provided in the PM_{10} SIP is 0.110 lb/ton. Therefore, in 2002 the PM_{10} emissions were below this limit (368.17 lb PM_{10}/yr)/(281,855.0 ton/yr) = 0.0013 lb/ton.

SBS Process Emissions

Process Unit	Sulfur Flow (LTPD)	SBS Exhaust	CEMS Data SO_2 Conc.	SO_2[1] (lb/hr)	SO_2 (tpy)	H_2SO_4 Mist	
						lb/hr[1]	tpy
SBS TGU	0.008	90.0	3	0.0	0.2	0.00	0.01

Beavon Stretford Process Emissions

No. of Days Combusting	Actual Airflow MAscf/hr	SO_2[1] lb/hr**	SO_2 tpy	H_2SO_4 Mist		H_2S lb/hr	H_2S tpy	Total Reduced Sulfur lb/hr	Total Reduced Sulfur tpy
				lb/hr[1]	tpy				
108	1,603	5.7	7.4	0.26	0.34	0.7	3.1	11.8	51.6

** The SO_2 concentration is calculated based on average daily H_2S and TRS CEMS Data.

The Beavon Stretford combustor temperature ramps up if the H_2S concentration approaches 10 ppm. BP Whiting has estimated that approximately 30% of the TRS/H2S sulfur is converted to SO_2 after the combustion temperature ramps up.

Sulfur Loading Emissions***

	H_2S Conc. (ppm)	Average Sulfur Stored (LTPD)	H_2S in sulfur (lb/hr)	H_2S in sulfur (ton/yr)	H_2S Emitted (lb/hr)	H_2S Emitted (ton/yr)	
Before Loading	250	344.9	8.1	35.4			
After Loading	200	344.9	6.5	28.3			
					1.6	7.1	

*** The difference in the amount of H_2S in the sulfur before and after loading is assumed to be emitted to atmosphere as part of the loading process.

[1] Hourly emission rate represents annual average hourly emissions.

**** Sulfur pit loading emissions have only been included for the H_2S/TRS baseline years of 2000-2001.

Table C.24. 2003 Sulfur Recovery Complex Emissions

Combustor Emissions

Process Unit	Natural Gas Usage (MMscf/yr)	VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				CO				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
SBS TGU	58.8	5.5	lb/MMscf	0.0	0.2	100	lb/MMscf	0.7	2.9	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.2	84	lb/MMscf	0.6	2.5	5.00E-04	lb/MMscf	3.4E-06	1.5E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
Beavon-Stretford TGU	47.3	5.5	lb/MMscf	0.0	0.1	100	lb/MMscf	0.5	2.4	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.2	84	lb/MMscf	0.5	2.0	5.00E-04	lb/MMscf	2.7E-06	1.2E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
SRU Incinerator	77.2	5.5	lb/MMscf	0.0	0.2	100	lb/MMscf	0.9	3.9	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.3	84	lb/MMscf	0.7	3.2	5.00E-04	lb/MMscf	4.4E-06	1.9E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000

* The total flow to the Beavon-Stretford TGU in 2003 was 261,933.7 ton/yr based on data recorded by the BP Whiting PI data collection system.
Note the PM_{10} emission limit provided in the PM_{10} SIP is 0.110 lb/ton. Therefore, in 2003 the PM_{10} emissions were below this limit (359.2 lb PM_{10}/yr)/(261,933.7 ton/yr) = 0.0014 lb/ton.

SBS Process Emissions

Process Unit	Sulfur Flow (LTPD)	SBS Exhaust	CEMS Data SO_2 Conc.	SO_2[1] (lb/hr)	SO_2 (tpy)	H_2SO_4 Mist	
						lb/hr[1]	tpy
SBS TGU	0.036	337.8	8	0.4	2.0	0.02	0.09

Beavon Stretford Process Emissions

No. of Days Combusting	Actual Airflow MAscf/hr	SO_2[1] lb/hr**	SO_2 tpy	H_2SO_4 Mist		H_2S lb/hr	H_2S tpy	Total Reduced Sulfur lb/hr	Total Reduced Sulfur tpy
				lb/hr[1]	tpy				
199	1,033	7.2	17.1	0.33	0.79	1.1	4.8	12.8	56.1

** The SO_2 concentration is calculated based on average daily H_2S and TRS CEMS Data.

The Beavon Stretford combustor temperature ramps up if the H_2S concentration approaches 10 ppm. BP Whiting has estimated that approximately 30% of the TRS/H2S sulfur is converted to SO_2 after the combustion temperature ramps up.

Sulfur Loading Emissions***

	H_2S Conc. (ppm)	Average Sulfur Stored (LTPD)	H_2S in sulfur (lb/hr)	H_2S in sulfur (ton/yr)	H_2S Emitted (lb/hr)	H_2S Emitted (ton/yr)	
Before Loading	250	323.2	7.6	33.2			
After Loading	200	323.2	6.1	26.5			
					1.5	6.6	

*** The difference in the amount of H_2S in the sulfur before and after loading is assumed to be emitted to atmosphere as part of the loading process.
[1] Hourly emission rate represents annual average hourly emissions.
**** Sulfur pit loading emissions have only been included for the H_2S/TRS baseline years of 2000-2001.

Table C.25. 2004 Sulfur Recovery Complex Emissions

Combustor Emissions

Process Unit	Natural Gas Usage (MMscf/yr)	VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				CO				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
SBS TGU	79.2	5.5	lb/MMscf	0.0	0.2	100	lb/MMscf	0.9	4.0	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.3	84	lb/MMscf	0.8	3.3	5.00E-04	lb/MMscf	4.5E-06	2.0E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
Beavon-Stretford TGU	48.5	5.5	lb/MMscf	0.0	0.1	100	lb/MMscf	0.6	2.4	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.2	84	lb/MMscf	0.5	2.0	5.00E-04	lb/MMscf	2.8E-06	1.2E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
SRU Incinerator	56.7	5.5	lb/MMscf	0.0	0.2	100	lb/MMscf	0.6	2.8	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.0	0.2	84	lb/MMscf	0.5	2.4	5.00E-04	lb/MMscf	3.2E-06	1.4E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000

* The total flow to the Beavon-Stretford TGU in 2004 was 282,362.3 ton/yr based on data recorded by the BP Whiting PI data collection system.
Note the PM_{10} emission limit provided in the PM_{10} SIP is 0.110 lb/ton. Therefore, in 2004 the PM_{10} emissions were below this limit (368.9 lb PM_{10}/yr)/(282,362.3 ton/yr) = 0.0013 lb/ton.

SBS Process Emissions

Process Unit	Sulfur Flow (LTPD)	SBS Exhaust	CEMS Data SO_2 Conc.	SO_2[1] (lb/hr)	SO_2 (tpy)	H_2SO_4 Mist	
						lb/hr[1]	tpy
SBS TGU	0.083	467.8	14	1.1	5.0	0.05	0.23

Beavon Stretford Process Emissions

No. of Days Combusting	Actual Airflow MAscf/hr	SO_2[1] lb/hr**	SO_2 tpy	H_2SO_4 Mist		H_2S lb/hr	H_2S tpy	Total Reduced Sulfur lb/hr	Total Reduced Sulfur tpy
				lb/hr[1]	tpy				
5	1,267	3.4	0.2	0.16	0.01	0.2	0.7	4.5	19.9

** The SO_2 concentration is calculated based on average daily H_2S and TRS CEMS Data.

The Beavon Stretford combustor temperature ramps up if the H_2S concentration approaches 10 ppm. BP Whiting has estimated that approximately 30% of the TRS/H2S sulfur is converted to SO_2 after the combustion temperature ramps up.

Sulfur Loading Emissions***

	H_2S Conc. (ppm)	Average Sulfur Stored (LTPD)	H_2S in sulfur (lb/hr)	H_2S in sulfur (ton/yr)	H_2S Emitted (lb/hr)	H_2S Emitted (ton/yr)	
Before Loading	250	305.4	7.2	31.4			
After Loading	200	305.4	5.7	25.1			
					1.4	6.3	

*** The difference in the amount of H2S in the sulfur before and after loading is assumed to be emitted to atmosphere as part of the loading process.
[1] Hourly emission rate represents annual average hourly emissions.
**** Sulfur pit loading emissions have only been included for the H_2S/TRS baseline years of 2000-2001.

Table C.26. Project Cooling Tower Emissions

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Existing Unaffected Cooling Towers to be Controlled for PM Emission Reductions

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 2[2]	25,000	gpm	1,285	gpm	1,627	0.001%	1.29E-04	lb/1000 gal	0.2	0.9
Cooling Tower 3	90,000	gpm	1,571	gpm	1,147	0.001%	9.08E-05	lb/1000 gal	0.5	2.2
Cooling Tower 4	44,000	gpm	1,085	gpm	1,645	0.001%	1.30E-04	lb/1000 gal	0.4	1.5

Shutdown Cooling Tower

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
SBS Cooling Tower	-	-	-	-	-	-	-	-	-	-	-	-	-	-

New Cooling Towers

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 7	21,000	gpm	451	gpm	1,163	0.7	lb/MMgal	0.9	3.9	0.001%	9.20E-05	lb/1000 gal	0.1	0.5
Cooling Tower 8	90,000	gpm	2,956	gpm	1,163	0.7	lb/MMgal	3.9	17.1	0.001%	9.20E-05	lb/1000 gal	0.5	2.2
HU Cooling Tower[3]	14,000	gpm	0	gpm	6,300					0.001%	4.99E-04	lb/1000 gal	0.42	1.8

[1] Hourly emission rate represents annual average hourly emissions.
[2] Half of the Cooling Tower 2 modules were controlled prior to the CXHO Project. Contemporaneous to the CXHO Project the other modules will be controlled with high efficiency drift eliminators. Note the recirculation rate used in this calculation is half of the total Cooling Tower recirculation rate.
[3] The new hydrogen unit cooling tower will be operated separately from refinery operations. VOC emissions are only applicable to cooling towers serving petroleum refinery operations.

Cooling Tower VOC Emission Calculation

$$VOC\ \ Emissions\ \ = (R + M) * EF_{AP-42}$$

Where,
R = Recirculation rate (1,000 gal/min)
M = Make-up rate (1,000 gal/min)

$$Make\ -Up\ \ Rate\ \ = M_{AVG} * \frac{R_N}{R_{AVG}}$$

Where,
M_{AVG} = Average make-up rate for existing cooling towers 1 through 6 (gpm)
R_N = Recirculation rate for new cooling tower (gpm)
R_{AVG} = Average recirculation rate for existing cooling towers 1 through 6 (gpm)

Cooling Tower $PM/PM_{10}/PM_{2.5}$ Emission Factor Calculation

$$PM\ /\ PM_{10}\ /\ PM_{2.5}\ \ EF\ = PM\ \ EF_{AP-42} * \frac{TLD_{design}}{TLD_{AP-42}} * \frac{TDS_{future}}{TDS_{AP-42}}$$

Where,
PM EF_{AP-42} = AP-42 Emission Factor for PM10 (lb/1000 gal)
TLD_{design} = Design total liquid drift (%)
TLD_{AP-42} = Design total liquid drift (%)
TDS_{future} = Estimated future total dissolved solid content (mg/L)
TDS_{AP-42} = Total dissolved solid content used in AP-42 (mg/L)

Cooling Tower $PM/PM_{10}/PM_{2.5}$ Emission Calculation

$$PM\ /\ PM_{10}\ /\ PM_{2.5}\ = (R + M) * PM\ \ EF$$

Where,
R = Recirculation rate (1,000 gal/min)
M = Make-up rate (1,000 gal/min)

Table C.27. 2000 Cooling Tower Emissions

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Existing Unaffected Cooling Towers to be Controlled for PM Emission Reductions

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 2[2]	25,000	gpm	1,248	gpm	1,748	0.02%	2.77E-03	lb/1000 gal	4.2	18.2
	25,000	gpm	1,248	gpm	1,748	0.001%	1.38E-04	lb/1000 gal	0.2	0.9
Cooling Tower 3	90,000	gpm	1,459	gpm	728	0.02%	1.15E-03	lb/1000 gal	6.2	27.3
Cooling Tower 4	44,000	gpm	1,085	gpm	1,018	0.02%	1.61E-03	lb/1000 gal	4.3	18.6

Shutdown Cooling Tower

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
SBS Cooling Tower[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Hourly emission rate represents annual average hourly emissions.
[2] Only half of the Cooling Tower 2 modules were controlled by high efficiency drift eliminators in 2000.
[3] Unit was not operated during the 2000 baseline year.

Table C.28. 2001 Cooling Tower Emissions

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Existing Unaffected Cooling Towers to be Controlled for PM Emission Reductions

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 2[2]	25,000	gpm	1,248	gpm	1,413	0.02%	2.24E-03	lb/1000 gal	3.4	14.7
	25,000	gpm	1,248	gpm	1,413	0.001%	1.12E-04	lb/1000 gal	0.2	0.7
Cooling Tower 3	90,000	gpm	1,459	gpm	798	0.02%	1.26E-03	lb/1000 gal	6.8	29.9
Cooling Tower 4	44,000	gpm	1,085	gpm	829	0.02%	1.31E-03	lb/1000 gal	3.5	15.2

Shutdown Cooling Tower

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
SBS Cooling Tower	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Hourly emission rate represents annual average hourly emissions.
[2] Only half of the Cooling Tower 2 modules were controlled by high efficiency drift eliminators in 2001.
[3] Unit was not operated during the 2001 baseline year.

Table C.29. 2002 Cooling Tower Emissions

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Existing Unaffected Cooling Towers to be Controlled for PM Emission Reductions

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 2[2]	25,000	gpm	1,248	gpm	1,627	0.02%	2.58E-03	lb/1000 gal	3.9	16.9
	25,000	gpm	1,248	gpm	1,627	0.001%	1.29E-04	lb/1000 gal	0.2	0.8
Cooling Tower 3	90,000	gpm	1,459	gpm	1,001	0.02%	1.58E-03	lb/1000 gal	8.6	37.5
Cooling Tower 4	44,000	gpm	1,085	gpm	1,221	0.02%	1.93E-03	lb/1000 gal	5.1	22.4

Shutdown Cooling Tower

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
SBS Cooling Tower	4,100	gpm	91	gpm	958	0.7	lb/MMgal	0.2	0.8	0.02%	1.52E-03	lb/1000 gal	0.4	1.6

[1] Hourly emission rate represents annual average hourly emissions.
[2] Only half of the Cooling Tower 2 modules were controlled by high efficiency drift eliminators in 2002.

Table C.30. 2003 Cooling Tower Emissions

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Existing Unaffected Cooling Towers to be Controlled for PM Emission Reductions

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 2[2]	25,000	gpm	1,248	gpm	1,425	0.02%	2.26E-03	lb/1000 gal	3.4	14.8
	25,000	gpm	1,248	gpm	1,425	0.001%	1.13E-04	lb/1000 gal	0.2	0.7
Cooling Tower 3	90,000	gpm	1,459	gpm	1,126	0.02%	1.78E-03	lb/1000 gal	9.6	42.2
Cooling Tower 4	44,000	gpm	1,085	gpm	1,153	0.02%	1.83E-03	lb/1000 gal	4.8	21.1

Shutdown Cooling Tower

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
SBS Cooling Tower	4,100	gpm	91	gpm	958	0.7	lb/MMgal	0.2	0.8	0.02%	1.52E-03	lb/1000 gal	0.4	1.6

[1] Hourly emission rate represents annual average hourly emissions.
[2] Only half of the Cooling Tower 2 modules were controlled by high efficiency drift eliminators in 2003.

Table C.31. 2004 Cooling Tower Emissions

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Existing Unaffected Cooling Towers to be Controlled for PM Emission Reductions

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 2[2]	25,000	gpm	1,285	gpm	1,596	0.02%	2.53E-03	lb/1000 gal	3.8	16.6
	25,000	gpm	1,285	gpm	1,596	0.001%	1.26E-04	lb/1000 gal	0.2	0.8
Cooling Tower 3	90,000	gpm	1,571	gpm	1,147	0.02%	1.82E-03	lb/1000 gal	9.8	43.0
Cooling Tower 4	44,000	gpm	1,042	gpm	1,645	0.02%	2.60E-03	lb/1000 gal	6.9	30.1

Shutdown Cooling Tower

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
SBS Cooling Tower	4,100	gpm	155	gpm	825	0.7	lb/MMgal	0.2	0.8	0.02%	1.31E-03	lb/1000 gal	0.3	1.4

[1] Hourly emission rate represents annual average hourly emissions.
[2] Only half of Cooling Tower 2 modules were controlled by high efficiency drift eliminators in 2004.

Table C.32. Project Fugitive Dust Emissions - Coke Handling

Aggregate Handling - Normal Operating Scenario

Total Coke Handled	2,080,500	tons/yr
Transfer Points	10	
Percentage of Operating Time[1]	95%	

Emission Calculation Variables	PM	$PM_{10}/PM_{2.5}$	Unit
Particle Size Multiplier (k)[2]	0.74	0.35	
Average Wind Speed in NW Indiana[3] (U)	10.4	10.4	mph
Material Moisture Content for Transfer Points (M)[4]	8	8	%
Percent Control for Transfer Point[5] 1, 10	70	70	%
Percent Control for Transfer Points[6] 2 through 9	90	90	%

Emission Calculation

Coke Handling	PM		PM_{10}		$PM_{2.5}$	
	lb/hr[7]	tpy	lb/hr[7]	tpy	lb/hr[7]	tpy
Transfer Points 1, 10	0.1	0.5	0.1	0.3	0.1	0.3
Transfer Points 2 - 9	0.2	0.7	0.1	0.3	0.1	0.3

$$EF = k * 0.0032 * \frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}} \quad \left(\frac{\text{lb PM}}{\text{ton coke handled}}\right)$$

[1] Percentage of operating time in normal and emergency scenarios provided by coke handling contract
[2] Emission factors provided in AP-42 Section 13.2.4 (January 1995).
[3] Based on average annual wind speed for Chicago, IL in U.S. EPA TANKS 4.0.9d.
[4] Based on assumed worst case moisture content of petroleum coke
[5] Percentage control provided by enclosed conveyors and water spray
[6] Percentage control provided by enclosed building and water spray.
[7] Hourly emission rate represents annual average hourly emissions.

Table C.33. Project Fugitive Dust Emissions - Coke Handling (Alternate Operating Scenario)

Aggregate Handling - Emergency Operation Scenario

Total Coke Handled	109,500	tons/yr
Transfer Points	4	
Percentage of Operating Time[1]	5%	

Emission Calculation Variables	PM	$PM_{10}/PM_{2.5}$	Unit
Particle Size Multiplier (k)[2]	0.74	0.35	
Average Wind Speed in NW Indiana[3](U)	10.4	10.4	mph
Material Moisture Content for Transfer Points (M)[4]	8	8	%
Percent Control for Transfer Points[5] 1, 2, 3	40	40	%
Percent Control for Transfer Point[6] 4	0	0	%

Emission Calculation

Coke Handling	PM		PM_{10}		$PM_{2.5}$	
	lb/hr[7]	tpy	lb/hr[7]	tpy	lb/hr[7]	tpy
Transfer Point 1, 2, 3	0.020	0.087	0.009	0.041	0.009	0.041
Transfer Point 4	0.011	0.048	0.005	0.023	0.005	0.023

$$EF = k * 0.0032 * \frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}} \quad \left(\frac{\text{lb PM}}{\text{ton coke handled}}\right)$$

[1] Percentage of operating time in normal and emergency scenarios provided by coke handling contractor
[2] Emission factors provided in AP-42 Section 13.2.4 (January 1995).
[3] Based on average annual wind speed for Chicago, IL in U.S. EPA TANKS 4.0.9d.
[4] Based on assumed worst case moisture content of petroleum coke
[5] Percentage control provided by enclosed conveyors
[6] No control for transfer into rail cars assumed for emergency operating scenario
[7] Hourly emission rate represents annual average hourly emissions.

Table C.34. 2001-2002 Coke Storage Emissions

Coke Aggregate Storage

Average Tons of Coke Produced per day[1]	1,638.9	tons/day
Average Tons of Coke Stored per pile/day (coke shipped out 5 days per week)	2,300.8	tons/day
Average Pile Height	14	ft
Density of Coke	56	lb/ft^3
Pile 3A Exposed Surface Area[2]	0.40	acres
Pile 3B Exposed Surface Area[2]	0.40	acres
Total Coke Yard Surface Area[3]	2.24	acres

Emission Calculation Variables[4]	PM	PM_{10}[5]	$PM_{2.5}$[6]	Unit
Pile Silt Content of Aggregate (s)[7]	4.5	4.5	4.5	%
Yard Silt Content of Aggregate (s)[8]	10.4	10.4	10.4	%
Number of days with greater then 0.01 in. of precipitation per year (p)[9]	124	124	124	days
% of time the unobstructed wind speed exceeds 12 mph (f)[10]	33.4	33.4	33.4	%

Emission Calculation

Coke Storage	PM		PM_{10}		$PM_{2.5}$	
	lb/hr[11]	tpy	lb/hr[11]	tpy	lb/hr[11]	tpy
Pile 3A	0.2	0.9	0.1	0.4	0.1	0.4
Pile 3B	0.2	0.9	0.1	0.4	0.1	0.4
Coke Yard	2.5	11.0	1.3	5.5	1.3	5.5

[1] Average tons of coke produced per day based on annual coke production (on a dry basis) in 2001 and 2002, which was 1,138,511,050 and 1,036,797,400 lb/yr, respectively, adjusted to 10% moisture.

[2] Pile surface area is estimated based on the production of coke and pile height.

$$\text{Coke Produced}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Amount of Coke Produced}\left(\frac{\text{ton}}{\text{day}}\right) * 365\ \frac{\text{day}}{\text{yr}}$$

$$\text{Days Coke Loaded} = 5\ \frac{\text{days}}{\text{week}} * 52\ \frac{\text{weeks}}{\text{yr}} = 260\ \frac{day}{yr}$$

$$\text{Average Coke Stored}\left(\frac{\text{ton}}{\text{day}}\right) = \frac{\text{Coke Produced}\left(\frac{\text{ton}}{\text{yr}}\right)}{260\ \frac{\text{day}}{\text{yr}}}$$

$$\text{Volume of Coke Stored}\left(\text{ft}^3\right) = \text{Average Coke Stored}\left(\frac{\text{ton}}{\text{day}}\right) * \frac{2{,}000\ \text{lb}}{1\ \text{ton}} * \frac{\text{ft}^3}{56\ \text{lb}}$$

$$\text{Volume of Cone} = \frac{1}{3}\pi r^2 h$$

$$\text{Radius of Pile} = \sqrt{\left(\frac{3 * 71{,}296.36\ \text{ft}^3}{\pi * 14\ \text{ft}}\right)} = 69.73\ \text{ft}$$

$$\text{Exposed Pile Surface Area}\left(\text{acre}\right) = \pi * r^2 * \frac{1\ \text{acre}}{43{,}560\ \text{ft}^2}$$

[3] Coke yard surface area estimated from aerial image of coke yard.

[4] Based on Chapter 4 of the 1988 EPA Report "Control of Open Fugitive Dust Sources". (EPA - 450/3-88-008) The following equation calculated particulate emissions due to wind erosion of an continuously active pile.

$$EF = 1.7\left(\frac{s}{1.5}\right)\left(\frac{365-p}{235}\right)\left(\frac{f}{15}\right)\left(\frac{1\ \text{day}}{24\ \text{hour}}\right) \quad (\text{lb/hr/acre})$$

[5] The PM_{10} emission factor is estimated to be half of the PM emission factor based on 1988 EPA Report (EPA - 450/3-88-008).

[6] The $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

[7] Surface material silt content for storage pile from silt testing done on comparable coke pile.

[8] Surface material silt content for coke yard from silt testing on comparable coke yard.

[9] The number of wet days with at least 0.01 inches of precipitation is based on a 47 year average for Chicago, IL from the National Climate Data Center.

[10] Based on four years (1997-2001) of metrological data at Midway Airport.

[11] Hourly emission rate represents annual average hourly emissions.

Table C.35. 2001-2002 Coke Handling Emissions

Coke Aggregate Handling

Average Tons of Coke Produced per day	1,638.9	tons/day
Total Coke Handled[1]	598,210	ton/yr
Transfer Points[2]	3	

Emission Calculation Variables[3]	PM	$PM_{10}/PM_{2.5}$	Unit
Particle Size Multiplier (k)	0.74	0.35	
Average Wind Speed in NW Indiana (U)[4]	10.4	10.4	mph
Material Moisture Content (M)[5]	10	10	%

Emission Calculation

Coke Handling	PM		PM_{10}		$PM_{2.5}$[7]	
	lb/hr[6]	tpy	lb/hr[6]	tpy	lb/hr[6]	tpy
Total for Three Transfer Points	0.1	0.6	0.06	0.3	0.1	0.3

$$EF = k * 0.0032 * \frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}} \left(\frac{\text{lb PM}}{\text{ton coke handled}}\right)$$

Footnotes:

[1] Total coke handled based on average daily production during the baseline period.

$$\text{Total Coke Handled}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Average Coke Production}\left(\frac{\text{ton}}{\text{day}}\right) * 365\,\frac{\text{day}}{\text{yr}}$$

[2] The current coke handling includes three transfer points: (1) the drop into storage pile 3A or 3B from the front end loader (FEL), (2) loading out of storage pile 3A or 3B by a FEL, and (3) the drop into the truck from the FEL.

[3] Emission factors provided in AP-42 Section 13.2.4 (November 2006).

[4] Based on average annual wind speed for Chicago, IL in U.S. EPA TANKS 4.0.9d.

[5] Based on average moisture content for coke material handled provided by Natalie Grimmer via email on 1/4/2007.

[6] Hourly emission rate represents annual average hourly emissions.

[7] The $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

Table C.36. 2001-2002 Fugitive Emissions from Paved Roads

Coke Fugitive Dust from Paved Roads

Average Tons of Coke Produced per day	1,638.9	tons/day
Average Tons of Coke per Truck	21.5	ton/truck
Miles Driven Per Truck at Refinery	1.6	miles/truck
Vehicle Miles Traveled by Average Truck[1]	44,518	VMT/yr

Emission Calculation Variables[2]	PM	$PM_{10}/PM_{2.5}$	Unit
Particle Size Multiplier (k)[3]	0.082	0.016	lb/VMT
Road Surface Silt Loading (sL)[4]	9.7	9.7	g/m^2
Average Weight of Vehicles on Roads (W)[5]	25.8	25.8	ton
Number of Wet Days with at Least 0.01 in. of Precipitation (P)[6]	124	124	days
Number of Days in Averaging Period (N)	365	365	days
Emission Factor for Exhaust, Brake Wear and Tire Wear (C)[7]	0.00047	0.00047	lb/VMT

Emission Calculation

Paved Road Emissions	PM		PM_{10}		$PM_{2.5}$[9]	
	lb/hr[8]	tpy	lb/hr[8]	tpy	lb/hr[8]	tpy
Average Truck	26.8	117.2	5.2	22.9	5.2	22.9

$$EF = \left[k\left(\frac{sL}{2}\right)^{0.65}\left(\frac{W}{3}\right)^{1.5} - C \right]\left(1 - \frac{P}{4N}\right) \quad \text{(lb/VMT)}$$

Footnotes:

[1] Each truck travels a total of 1.6 miles within the Whiting Refinery on paved and swept roads.

$$\text{Vehicle Miles Traveled}\left(\frac{\text{VMT}}{\text{yr}}\right) = \frac{\text{Average Coke Production}\left(\frac{\text{ton}}{\text{day}}\right) * 365\,\frac{\text{day}}{\text{yr}}}{\text{Average Coke Loaded on Each Truck}\left(\frac{\text{ton}}{\text{truck}}\right)} * \text{Miles Traveled}\left(\frac{\text{miles}}{\text{truck}}\right)$$

[2] Emission factors provided in AP-42 Section 13.2.1 (November 2006).
[3] Particle size multiplier k from AP-42 Table 13.2.1-1 (November 2006).
[4] Road surface silt loading is from Table 13.2.1-4 and is based on the average silt loading for the iron and steel production industry.
[5] Since each truck travels 0.8 miles unloaded (weighing 15 tons) and 0.8 miles loaded (weighing 36.5 tons), the the average truck weight is 25.8 tons.
[6] The number of wet days with at least 0.01 inches of precipitation is based on a 47 year average for Chicago, IL from the National Climate Data Center.
[7] The emission factor for vehicle fleet exhaust, break and tire wear is from AP-42 Table 13.2.1-2 (November 2006).
[8] Hourly emission rate represents annual average hourly emissions.
[9] The $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

Table C.37. 2001-2002 Fugitive Emissions from Unpaved Roads

Coke Fugitive Dust from Unpaved Roads

Average Tons of Coke Produced per day	1,638.9	tons/day
Average Tons of Coke per Truck	21.5	ton/truck
Feet Driven Per Truck within Coke Yard	640	feet/truck
Feet Driven Per Front End Loader (FEL)	1,320	FEL feet driven/truck
Vehicle Miles Traveled by Average Trucks[1]	3,373	VMT/yr
Vehicle Miles Traveled by Average FEL[1]	6,956	VMT/yr

Emission Calculation Variables[2]	PM	PM_{10}	Unit
Empirical Constant (k)[3]	4.9	1.5	lb/VMT
Empirical Constant (a)[3]	0.7	0.9	
Empirical Constant (b)[3]	0.45	0.45	
Surface Material Silt Content (s)[4]	10.4	10.4	%
Average Weight of Trucks on Roads (W)[5]	25.8	25.8	ton
Average Weight of FEL on Roads (W)[6]	48.4	48.4	ton
Number of Wet Days with at Least 0.01 in. of Precipitation (P)[7]	124	124	%
Number of Days in Averaging Period (N)	365	365	days

Emission Calculation

Paved Road Emissions	PM		PM_{10}		$PM_{2.5}$[9]	
	lb/hr[8]	tpy	lb/hr[8]	tpy	lb/hr[8]	tpy
Average Truck	3.0	13.0	0.9	3.9	0.9	3.9
Average Front End Loader	8.1	35.6	2.4	10.6	2.4	10.6

$$EF = \left(k\left(\frac{s}{12}\right)^{a}\left(\frac{W}{3}\right)^{b}\right)\left(\frac{N-P}{N}\right) \quad (\text{lb/VMT})$$

Footnotes:

[1] Each truck travels either 360 ft (Pile 3A) or 280 ft (Pile 3B) each way to and from the coke pile inside the coke yard.

$$\text{Vehicle Miles Traveled}\left(\frac{\text{VMT}}{\text{yr}}\right) = \frac{\text{Average Coke Production}\left(\frac{\text{ton}}{\text{day}}\right) * 365\ \frac{\text{day}}{\text{yr}}}{\text{Average Coke Loaded on Each Truck}\left(\frac{\text{ton}}{\text{truck}}\right)} * \text{Feet Traveled}\left(\frac{\text{feet}}{\text{truck}}\right) * \frac{1\ \text{mile}}{5{,}280\ \text{feet}}$$

Note the FEL vehicle miles traveled are similarly calculated assuming either 460 ft (Pile 3A) or 120 ft (Pile 3B) of distance from the coker to the coke pile and an additional 40 ft of distance between the 3A or 3B coke pile and the truck being loaded. Note that given the capacity of the FEL relative to the trucks, each FEL trip must be made twice per each truck loaded.

[2] Emission factors provided in AP-42 Section 13.2.2 (November 2006).

[3] Emission constants k, a, and b from AP-42 Table 13.2.2-2.

[4] Surface material silt content from silt testing performed at comparable coke yard.

[5] Since each truck travels the same distance unloaded (weighing 15 tons) and loaded (weighing 36.5 tons), the the average truck weight is 25.8 tons.

[5] Since each FEL travels the same distance unloaded (weighing 42.1 tons) and loaded (weighing 54.6 tons), the the average FEL weight is 48.4 tons.

[6] The number of wet days with at least 0.01 inches of precipitation is based on a 47 year average for Chicago, IL from the National Climate Data Center.

[7] Hourly emission rate represents annual average hourly emissions.

[8] The $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

Table C.38. Project Flare Pilot and Purge Gas Combustion Emissions (Normal Operation)

Process Unit	Pilot Rates		VOC				NO_X				SO_2				PM				$PM_{10}/PM_{2.5}$ (filterable + condensable)				CO				Pb				H_2SO_4 Mist		Hg				Be			
			EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
GOHT Flare	420	scfh	5.5	lb/MMscf	0.0	0.01	100	lb/MMscf	0.0	0.2	0.60	lb/MMscf	0.0	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.01	84	lb/MMscf	0.0	0.2	5.0E-04	lb/MMscf	2.1E-07	9.2E-07	0.00	0.00	1.8E-04	lb/MMscf	7.7E-08	3.4E-07	1.2E-05	lb/MMscf	5.0E-09	2.2E-08
South Flare	420	scfh	5.5	lb/MMscf	0.0	0.01	100	lb/MMscf	0.0	0.2	0.60	lb/MMscf	0.00	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.01	84	lb/MMscf	0.0	0.2	5.0E-04	lb/MMscf	2.1E-07	9.2E-07	0.00	0.00	1.8E-04	lb/MMscf	7.7E-08	3.4E-07	1.2E-05	lb/MMscf	5.0E-09	2.2E-08
HU Flare	255	scfh	5.5	lb/MMscf	0.0	0.01	100	lb/MMscf	0.0	0.1	0.60	lb/MMscf	0.00	0.00	1.9	lb/MMscf	0.0	0.002	7.6	lb/MMscf	0.0	0.0	84	lb/MMscf	0.0	0.1	5.0E-04	lb/MMscf	1.3E-07	5.6E-07	0.00	0.00	1.8E-04	lb/MMscf	4.7E-08	2.1E-07	1.2E-05	lb/MMscf	3.1E-09	1.3E-08

Process Unit	Purge Rates		VOC				NO_X				SO_2				PM				$PM_{10}/PM_{2.5}$ (filterable + condensable)				CO				Pb				H_2SO_4 Mist		Hg				Be			
			EF	Unit	lb/hr[1]	tpy[2]	EF	Unit	lb/hr[1]	tpy[2]	EF[3]	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy[2]	EF	Unit	lb/hr[1]	tpy[2]	EF	Unit	lb/hr[1]	tpy[2]	EF	Unit	lb/hr[1]	tpy[2]	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy[2]	EF	Unit	lb/hr[1]	tpy[2]
GOHT Flare	2,820	scfh	0.14	lb/MMBtu	0.5	2.1	0.068	lb/MMBtu	0.2	1.0	13.30	lb/MMscf	0.0	0.2	1.9	lb/MMscf	0.0	0.02	7.6	lb/MMscf	0.0	0.1	0.37	lb/MMBtu	1.3	5.5	5.0E-04	lb/MMscf	1.7E-06	7.3E-06	0.00	0.01	1.8E-04	lb/MMscf	6.1E-07	2.7E-06	1.2E-05	lb/MMscf	6.1E-07	2.7E-06
South Flare	3,300	scfh	0.14	lb/MMBtu	0.6	2.4	0.068	lb/MMBtu	0.3	1.2	13.30	lb/MMscf	0.04	0.2	1.9	lb/MMscf	0.0	0.03	7.6	lb/MMscf	0.0	0.1	0.37	lb/MMBtu	1.5	6.4	5.0E-04	lb/MMscf	1.9E-06	8.5E-06	0.00	0.01	1.8E-04	lb/MMscf	1.9E-06	8.5E-06	1.2E-05	lb/MMscf	1.9E-06	8.5E-06

1. Hourly emission rate represents annual average hourly emissions.
2. Calculation accounts for annual average design refinery fuel gas higher heating value of 1,203.3 Btu/scf.
3. Emission factor accounts for annual average design refinery fuel gas total sulfur concentration of 80 ppm.
4. The HU Flare will not be designed with a purge. Therefore, no purging emissions are included.

Table C.39. Fugitive Emission Factors

Equipment/Service	EPA Refinery Average Emission Factors		EPA Refinery SCREEING Emission Factors - LEAK		EPA Refinery SCREEING Emission Factors - NO LEAK	
	Kg/hr/source	**lbs/hr/source**	**Kg/hr/source**	**lbs/hr/source**	**Kg/hr/source**	**lbs/hr/source**
Valves						
Gas/Vapor	0.0268	0.059083816	0.2626	0.5789	0.0006	0.0013
Light Liquid	0.0109	0.024030358	0.0852	0.1878	0.0017	0.0037
Heavy Liquid	0.00023	0.000507063	0.00023	0.00051	0.00023	0.00051
Pumps						
Light Liquid	0.114	0.25132668	0.437	0.963	0.012	0.0265
Heavy Liquid	0.021	0.04629702	0.3885	0.8565	0.0135	0.02976
Flanges						
Gas/Vapor	0.00025	0.00055	0.0375	0.0827	0.00006	0.00013
Light Liquid	0.00025	0.00055	0.0375	0.0827	0.00006	0.00013
Heavy Liquid	0.00025	0.00055	0.0375	0.0827	0.00006	0.00013
Compressors	0.636	1.40214	1.608	3.545	0.0894	0.1971
Relief Valves	0.16	0.35274	1.691	3.728	0.0447	0.0985
Open-ended Lines	0.0023	0.00507	0.01195	0.02635	0.0015	0.0033
Sampling Connections	0.015	0.03307	0.0375	0.0827	0.00006	0.00013

Reference:

A Factors are taken from EPA Document EPA-453/R-95-017, Nov. 1995, Table 2-2, Page 2-13.

B Factors are taken from EPA Document EPA-453/R-95-017, Nov. 1995, Table 2-6, Page 2-20.

Table C.40. Fugitive Emission Calculations for 4 Ultraformer (4UF)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	56	0.5789	0.0013	2.0%	0.7197	95%	100%	0.16
Light Liquid	13	0.1878	0.0037	2.0%	0.0960	95%	100%	0.02
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	113	0.0827	0.00013	0.3%	0.0427	30%	100%	0.13
Light Liquid	6	0.0827	0.00013	0.3%	0.0023	30%	100%	0.01
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	1	3.728	0.0985	2.0%	0.1711	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.32**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.41. Fugitive Emission Calculations for 3 Ultraformer (3UF)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	-887	0.5789	0.0013	2.0%	-11.3997	95%	100%	-2.50
Light Liquid	-744	0.1878	0.0037	2.0%	-5.4922	95%	100%	-1.20
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	-11	0.963	0.0265	2.0%	-0.4975	80%	100%	-0.44
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	-1,912	0.0827	0.00013	0.3%	-0.7222	30%	100%	-2.21
Light Liquid	-2,828	0.0827	0.00013	0.3%	-1.0682	30%	100%	-3.27
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	-1	3.545	0.1971	2.0%	-0.2640	0%	100%	-1.16
Relief Valves	-13	3.728	0.0985	2.0%	-2.2242	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	-1	0.0827	0.00013	2.0%	-0.0018	0%	100%	-0.01
							Total VOC Emissions (tons/yr):	**-10.79**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.42. Fugitive Emission Calculations for 12 Pipestill (12PS)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	114	0.5789	0.0013	2.0%	1.4651	95%	100%	0.32
Light Liquid	197	0.1878	0.0037	2.0%	1.4543	95%	100%	0.32
Heavy Liquid	394	0.00051	0.00051	2.0%	0.2009	30%	100%	0.62
Pumps								
Light Liquid	3	0.963	0.0265	2.0%	0.1357	80%	100%	0.12
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	456	0.0827	0.00013	0.3%	0.1722	30%	100%	0.53
Light Liquid	788	0.0827	0.00013	0.3%	0.2976	30%	100%	0.91
Heavy Liquid	1,576	0.0827	0.00013	0.3%	0.5953	30%	100%	1.83
Compressors	1	3.545	0.1971	2.0%	0.2640	0%	100%	1.16
Relief Valves	6	3.728	0.0985	2.0%	1.0265	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**5.80**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.43. Fugitive Emission Calculations for Distillate Hydrotreater (DHT)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	99	0.5789	0.0013	2.0%	1.2723	95%	100%	0.28
Light Liquid	51	0.1878	0.0037	2.0%	0.3765	95%	100%	0.08
Heavy Liquid	33	0.00051	0.00051	2.0%	0.0168	30%	100%	0.05
Pumps								
Light Liquid	1	0.963	0.0265	2.0%	0.0452	80%	100%	0.04
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	105	0.0827	0.00013	0.3%	0.0397	30%	100%	0.12
Light Liquid	16	0.0827	0.00013	0.3%	0.0060	30%	100%	0.02
Heavy Liquid	24	0.0827	0.00013	0.3%	0.0091	30%	100%	0.03
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	4	3.728	0.0985	2.0%	0.6844	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.62**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.44. Fugitive Emission Calculations for New Coker (#2 Coker)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	1,367	0.5789	0.0013	2.0%	17.5687	95%	100%	3.85
Light Liquid	1,367	0.1878	0.0037	2.0%	10.0912	95%	100%	2.21
Heavy Liquid	3,498	0.00051	0.00051	2.0%	1.7840	30%	100%	5.47
Pumps								
Light Liquid	16	0.963	0.0265	2.0%	0.7237	80%	100%	0.63
Heavy Liquid	8	0.8565	0.02976	2.0%	0.3704	80%	100%	0.32
Flanges								
Gas/Vapor	2,196	0.0827	0.00013	0.3%	0.8295	30%	100%	2.54
Light Liquid	2,196	0.0827	0.00013	0.3%	0.8295	30%	100%	2.54
Heavy Liquid	5,802	0.0827	0.00013	0.3%	2.1915	30%	100%	6.72
Compressors	1	3.545	0.1971	2.0%	0.2640	0%	100%	1.16
Relief Valves	30	3.728	0.0985	2.0%	5.1327	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	16	0.0827	0.00013	2.0%	0.0285	0%	100%	0.12
							Total VOC Emissions (tons/yr):	**25.57**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.45. Fugitive Emission Calculations for Existing Coker (11B PS)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	-1,094	0.5789	0.0013	2.0%	-14.0601	95%	100%	-3.08
Light Liquid	-1,094	0.1878	0.0037	2.0%	-8.0759	95%	100%	-1.77
Heavy Liquid	-2,798	0.00051	0.00051	2.0%	-1.4270	30%	100%	-4.38
Pumps								
Light Liquid	-13	0.963	0.0265	2.0%	-0.5880	80%	100%	-0.52
Heavy Liquid	-6	0.8565	0.02976	2.0%	-0.2778	30%	100%	-0.85
Flanges								
Gas/Vapor	-1,757	0.0827	0.00013	0.3%	-0.6636	30%	100%	-2.03
Light Liquid	-1,757	0.0827	0.00013	0.3%	-0.6636	30%	100%	-2.03
Heavy Liquid	-4,642	0.0827	0.00013	0.3%	-1.7533	30%	100%	-5.38
Compressors	-1	3.545	0.1971	2.0%	-0.2640	0%	100%	-1.16
Relief Valves	-24	3.728	0.0985	2.0%	-4.1062	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	-13	0.0827	0.00013	2.0%	-0.0232	0%	100%	-0.10
							Total VOC Emissions (tons/yr):	**-21.29**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.46. Fugitive Emission Calculations for Gas Oil Hydrotreater (GOHT)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	915	0.5789	0.0013	2.0%	11.7596	95%	100%	2.58
Light Liquid	912	0.1878	0.0037	2.0%	6.7324	95%	100%	1.47
Heavy Liquid	1,380	0.00051	0.00051	2.0%	0.7038	30%	100%	2.16
Pumps								0.00
Light Liquid	8	0.963	0.0265	2.0%	0.3618	80%	100%	0.32
Heavy Liquid	1	0.8565	0.02976	2.0%	0.0463	80%	100%	0.04
Flanges								
Gas/Vapor	3,660	0.0827	0.00013	0.3%	1.3824	30%	100%	4.24
Light Liquid	3,648	0.0827	0.00013	0.3%	1.3779	30%	100%	4.22
Heavy Liquid	7,475	0.0827	0.00013	0.3%	2.8234	30%	100%	8.66
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	26	3.728	0.0985	2.0%	4.4483	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**23.68**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.47. Fugitive Emission Calculations for New Hydrogen Unit (3rd Party SMR)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	692	0.5789	0.0013	2.0%	8.8936	95%	100%	1.95
Light Liquid	219	0.1878	0.0037	2.0%	1.6167	95%	100%	0.35
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	6	0.963	0.0265	2.0%	0.2714	80%	100%	0.24
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	2,768	0.0827	0.00013	0.3%	1.0455	30%	100%	3.21
Light Liquid	876	0.0827	0.00013	0.3%	0.3309	30%	100%	1.01
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	15	3.728	0.0985	2.0%	2.5664	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**6.76**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.48. Fugitive Emission Calculations for OSBL

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	53	0.5789	0.0013	2.0%	0.6812	95%	100%	0.15
Light Liquid	53	0.1878	0.0037	2.0%	0.3912	95%	100%	0.09
Heavy Liquid	26	0.00051	0.00051	2.0%	0.0133	30%	100%	0.04
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	212	0.0827	0.00013	0.3%	0.0801	30%	100%	0.25
Light Liquid	212	0.0827	0.00013	0.3%	0.0801	30%	100%	0.25
Heavy Liquid	104	0.0827	0.00013	0.3%	0.0393	30%	100%	0.12
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.89**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.49. Fugitive Emission for Sulfur Recovery Complex

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	73	0.5789	0.0013	2.0%	0.9382	95%	100%	0.21
Light Liquid	11	0.1878	0.0037	2.0%	0.0812	95%	100%	0.02
Heavy Liquid	22	0.00051	0.00051	2.0%	0.0112	30%	100%	0.03
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	292	0.0827	0.00013	0.3%	0.1103	30%	100%	0.34
Light Liquid	44	0.0827	0.00013	0.3%	0.0166	30%	100%	0.05
Heavy Liquid	88	0.0827	0.00013	0.3%	0.0332	30%	100%	0.10
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	2	3.728	0.0985	2.0%	0.3422	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							VOC Emissions w/o Amine Unit (tons/yr):	**0.75**
							Amine Unit Emissions (tons/year):	**1.72**
							Total VOC Emissions (tons/year):	**2.46**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.50. Fugitive Emission for Claus Offgas Treater 1

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	0	0.1878	0.0037	2.0%	0.0000	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							VOC Emissions w/o Amine Unit (tons/yr):	**0.00**
							Amine Unit Emissions (tons/year):	**0.86**
							Total VOC Emissions (tons/year):	**0.86**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.51. Fugitive Emission for Claus Offgas Treater 2

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	0	0.1878	0.0037	2.0%	0.0000	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							VOC Emissions w/o Amine Unit (tons/yr):	**0.00**
							Amine Unit Emissions (tons/year):	**0.86**
							Total VOC Emissions (tons/year):	**0.86**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.52. Fugitive Emission for No 4 Treatment Plant

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	-5	0.5789	0.0013	2.0%	-0.0643	95%	100%	-0.01
Light Liquid	-59	0.1878	0.0037	2.0%	-0.4355	95%	100%	-0.10
Heavy Liquid	-10	0.00051	0.00051	2.0%	-0.0051	30%	100%	-0.02
Pumps								
Light Liquid	-1	0.963	0.0265	2.0%	-0.0452	80%	100%	-0.04
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	-20	0.0827	0.00013	0.3%	-0.0076	30%	100%	-0.02
Heavy Liquid	-40	0.0827	0.00013	0.3%	-0.0151	30%	100%	-0.05
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	-1	3.728	0.0985	2.0%	-0.1711	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**-0.23**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.53. Fugitive Emission for ARU

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	26	0.5789	0.0013	2.0%	0.3342	95%	100%	0.07
Light Liquid	94	0.1878	0.0037	2.0%	0.6939	95%	100%	0.15
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	17	0.0827	0.00013	0.3%	0.0064	30%	100%	0.02
Light Liquid	57	0.0827	0.00013	0.3%	0.0215	30%	100%	0.07
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.31**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.54. Fugitive Emission for BOU

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	8	0.5789	0.0013	2.0%	0.1028	95%	100%	0.02
Light Liquid	0	0.1878	0.0037	2.0%	0.0000	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	2	0.0827	0.00013	0.3%	0.0008	30%	100%	0.00
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.02**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.55. Fugitive Emission for ISOM

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	55	0.5789	0.0013	2.0%	0.7069	95%	100%	0.15
Light Liquid	0	0.1878	0.0037	2.0%	0.0000	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	23	0.0827	0.00013	0.3%	0.0087	30%	100%	0.03
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	2	3.728	0.0985	2.0%	0.3422	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.18**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.56. Fugitive Emission for VRU300

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	-360	0.5789	0.0013	2.0%	-4.6267	95%	100%	-1.01
Light Liquid	-685	0.1878	0.0037	2.0%	-5.0567	95%	100%	-1.11
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	-12	0.963	0.0265	2.0%	-0.5428	80%	100%	-0.48
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	-720	0.0827	0.00013	0.3%	-0.2720	30%	100%	-0.83
Light Liquid	-1,370	0.0827	0.00013	0.3%	-0.5175	30%	100%	-1.59
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	-1	3.545	0.1971	2.0%	-0.2640	0%	100%	-1.16
Relief Valves	-18	3.728	0.0985	2.0%	-3.0796	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**-6.17**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.57. Fugitive Emission for DDU

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	25	0.5789	0.0013	2.0%	0.3213	95%	100%	0.07
Light Liquid	70	0.1878	0.0037	2.0%	0.5167	95%	100%	0.11
Heavy Liquid	8	0.00051	0.00051	2.0%	0.0041	30%	100%	0.01
Pumps								
Light Liquid	1	0.963	0.0265	2.0%	0.0452	80%	100%	0.04
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	15	0.0827	0.00013	0.3%	0.0057	30%	100%	0.02
Light Liquid	35	0.0827	0.00013	0.3%	0.0132	30%	100%	0.04
Heavy Liquid	4	0.0827	0.00013	0.3%	0.0015	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.30**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.58. Fugitive Emission for 1SPS

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	-194	0.5789	0.0013	2.0%	-2.4933	95%	100%	-0.55
Light Liquid	-10	0.1878	0.0037	2.0%	-0.0738	95%	100%	-0.02
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	-1	3.728	0.0985	2.0%	-0.1711	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**-0.56**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.59. Fugitive Component Count and Emissions Summary

EPA Refinery Screening Fugitive Emission Factor Basis

Unit Name=>	4 Ultraformer		3 Ultraformer		12 Pipestill		DHT		New Coker		11B Coker		Gas Oil Hyrdotreater		Hydrogen		OSBL		Sulfur Recovery		Sulfur Recovery		Sulfur Recovery		4TP		ARU		BOU		ISOM		VRU300		DDU	
Unit Code=>	4UF		3UF		12PS		DHT		FW Coker		11B Coker		GOHT		HU		OSBL		SRU		COT 1		COT 2		4TP		ARU		BOU		ISOM		VRU300		DDU	
	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)
Valves																																				
Gas/Vapor	56	0.2	-887	-2.5	114	0.3	99	0.3	1,367	3.8	-1,094	-3.1	915	2.6	692	1.9	53	0.1	73	0.2	0	0.0	0	0.0	-5	0.0	26	0.1	8	0.0	55	0.2	-360	-1.0	25	0.1
Light Liquid	13	0.0	-744	-1.2	197	0.3	51	0.1	1,367	2.2	-1,094	-1.8	912	1.5	219	0.4	53	0.1	11	0.0	0	0.0	0	0.0	-59	-0.1	94	0.2	0	0.0	0	0.0	-685	-1.1	70	0.1
Heavy Liquid	0	0.0	0	0.0	394	0.6	33	0.1	3,498	5.5	-2,798	-4.4	1,380	2.2	0	0.0	26	0.0	22	0.0	0	0.0	0	0.0	-10	0.0	0	0.0	0	0.0	0	0.0	0	0.0	8	0.0
Pumps																																				
Light Liquid	0	0.0	-11	-0.4	3	0.1	1	0.0	16	0.6	-13	-0.5	8	0.3	6	0.2	0	0.0	0	0.0	0	0.0	0	0.0	-1	0.0	0	0.0	0	0.0	0	0.0	-12	-0.5	1	0.0
Heavy Liquid	0	0.0	0	0.0	0	0.0	0	0.0	8	0.3	-6	-0.9	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Flanges																																				
Gas/Vapor	113	0.1	-1,912	-2.2	456	0.5	105	0.1	2,196	2.5	-1,757	-2.0	3,660	4.2	2,768	3.2	212	0.2	292	0.3	0	0.0	0	0.0	0	0.0	17	0.0	2	0.0	23	0.0	-720	-0.8	15	0.0
Light Liquid	6	0.0	-2,828	-3.3	788	0.9	16	0.0	2,196	2.5	-1,757	-2.0	3,648	4.2	876	1.0	212	0.2	44	0.1	0	0.0	0	0.0	-20	0.0	57	0.1	0	0.0	0	0.0	-1,370	-1.6	35	0.0
Heavy Liquid	0	0.0	0	0.0	1,576	1.8	24	0.0	5,802	6.7	-4,642	-5.4	7,475	8.7	0	0.0	104	0.1	88	0.1	0	0.0	0	0.0	-40	0.0	0	0.0	0	0.0	0	0.0	0	0.0	4	0.0
Compressors	0	0.0	-1	-1.2	1	1.2	0	0.0	1	1.2	-1	-1.2	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	-1	-1.2	0	0.0
Relief Valves	1	0.0	-13	0.0	6	0.0	4	0.0	30	0.0	-24	0.0	26	0.0	15	0.0	0	0.0	2	0.0	0	0.0	0	0.0	-1	0.0	0	0.0	0	0.0	2	0.0	-18	0.0	0	0.0
Open-ended Lines	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Sampling Connection	0	0.0	-1	0.0	0	0.0	0	0.0	16	0.1	-13	-0.1	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
	Totals:	**0.3**		**-10.8**		**5.8**		**0.6**		**25.6**		**-21.3**		**23.7**		**6.8**		**0.9**		**2.5**		**0.9**		**0.9**		**-0.2**		**0.3**		**0.0**		**0.2**		**-6.2**		**0.3**

OVERALL VOC TOTAL: 30.1 Tons/year

Table C.60. Fugitive Emission for Additional Existing Components in Heavy Liquid Service

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	Current LDAR Control Efficiency	Proposed LDAR Control Efficiency	Percent in VOC Service	Current VOC Emissions (Tons/yr)	Projected VOC Emissions (Tons/yr)	VOC Emission Reductions (Tons/yr)
Existing Pumps											
Heavy Liquid	269	0.8565	0.02976	2.0%	12.4533	30%	80%	100%	38.18	10.91	-27.27
									Total VOC Emissions (tons/yr):		**-27.27**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Table C.61. Project Marine Gasoline Loading Emissions

Gasoline Loaded		VOC			
		EF[2]	Unit	lb/hr[1]	tpy
4,000,000	bbl/yr	10	mg/L	1.6	7.0

Additional VRU emissions[2]

NOx (tpy)	CO (tpy)
5.6	2.2

[1] Hourly emission rate represents annual average hourly emissions.
[2] The Vapor Recovery Unit will control gasoline loading operations to 10 mg of VOC emissions per liter of product loaded. Vendor estimates include additional NOx and CO emissions.

Table C.62. 2003 Marine Loading Emissions

Gasoline Loaded			Vapor Pressure (psia)	MW	Temp (R)	VOC			
Product	Total	Unit				EF	Unit	lb/hr[1]	tpy
87R9+ REG	2,438,657	bbl/yr	5.016	65	530	3.832	lb/1000 gal	44.8	196.3
93R9+ PREM	161,495	bbl/yr	5.016	65	530	3.832	lb/1000 gal	3.0	13.0
							Total	**47.8**	**209.2**

AP-42 Section 5.2 Transportation and Marketing of Petroleum Liquids (01/95)

$$EF_{Load} = 12.46 * \frac{S * P * M}{T}$$

Where,

EF_{Load} = Loading Emission Factor (lb/1000 gal)

S = Saturation Factor (0.5 for submerged loading of a clean cargo tank)

P = True Vapor Pressure (psia)

M = Molecular Weight (lb/lbmol)

T = Temperature (R)

[1] Hourly emission rate represents annual average hourly emissions.

Table C.63. 2004 Marine Loading Emissions

Gasoline Loaded			Vapor Pressure (psia)	MW	Temp (R)	VOC			
Product	Total	Unit				EF	Unit	lb/hr[1]	tpy
ALKYLATE	42,146	bbl/yr	2.224	70	530	1.830	lb/1000 gal	0.4	1.6
HVN ULTRAFORMER FEED	95,007	bbl/yr	7.308	61	530	5.240	lb/1000 gal	2.4	10.5
93R9+ PREM	157,703	bbl/yr	5.016	65	530	3.832	lb/1000 gal	2.9	12.7
87R9+ REG	1,626,195	bbl/yr	5.016	65	530	3.832	lb/1000 gal	29.9	130.9
							Total	**35.5**	**155.6**

AP-42 Section 5.2 Transportation and Marketing of Petroleum Liquids (01/95)

$$EF_{Load} = 12.46 * \frac{S * P * M}{T}$$

Where,

EF_{Load} = Loading Emission Factor (lb/1000 gal)

S = Saturation Factor (0.5 for submerged loading of a clean cargo tank)

P = True Vapor Pressure (psia)

M = Molecular Weight (lb/lbmol)

T = Temperature (R)

[1] Hourly emission rate represents annual average hourly emissions.

Table C.64. Project Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	37.60	10^6 bbl/yr	103	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	14.2	62.0
FCU 600	24.09	10^6 bbl/yr	66	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	9.1	39.7

Process Unit	Usage[3,4]		$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
			EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	669,191	1000 lb coke burned/yr	0.465	lb/1000 lb coke burned	35.5	155.6	42	PPM @ 0% excess O_2	33.6	147.2	39.7	PPM @ 0% excess O_2	52.2	228.6	25	PPM @ 0% excess O_2	45.7	200.3	2.099	9.19	2.55E-04	lb/1000 lb coke burned	0.019	0.085	1.00E-06	lb/1000 lb coke burned	7.64E-05	3.35E-04	3.51E-06	lb/1000 lb coke burned	2.68E-04	1.17E-03
FCU 600	428,802	1000 lb coke burned/yr	0.350	lb/1000 lb coke burned	17.1	75.0	41	PPM @ 0% excess O_2	21.0	92.1	20	PPM @ 0% excess O_2	16.9	73.8	37	PPM @ 0% excess O_2	43.4	190.0	1.991	8.72	2.55E-04	lb/1000 lb coke burned	0.012	0.055	1.00E-06	lb/1000 lb coke burned	4.90E-05	2.14E-04	3.51E-06	lb/1000 lb coke burned	1.72E-04	7.53E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Future potential coke usage based on maximum annual average ratio of coke burned to fresh feed of 17.8 for FCU 500.
4. Future potential coke usage based on maximum annual average ratio of coke burned to fresh feed of 17.8 for FCU 600.
5. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must also be on a 0% O_2 basis.

Table C.65. 1999 Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	28.49	10^6 bbl/yr	78.1	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	10.7	47.0
FCU 600	21.71	10^6 bbl/yr	59.5	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	8.2	35.8

Process Unit	Usage		Excess Oxygen	$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
				EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	432,722	1000 lb coke burned/yr	1.90%	0.465	lb/1000 lb coke burned	23.0	100.6	26	PPM @ 1.9% excess O2	14.8	64.8	40	PPM @ 0% excess O_2	34.0	149.0	25	PPM @ 0% excess O_2	29.6	129.5	1.357	5.95	2.55E-04	lb/1000 lb coke burned	1.26E-02	5.52E-02	1.00E-06	lb/1000 lb coke burned	4.94E-05	2.16E-04	3.51E-06	lb/1000 lb coke burned	1.73E-04	7.59E-04
FCU 600	330,653	1000 lb coke burned/yr	1.4%	0.350	lb/1000 lb coke burned	13.2	57.9	22	PPM @ 1.4% excess O2	9.3	40.7	20	PPM @ 0% excess O_2	13.0	56.9	50	PPM @ 0% excess O_2	45.2	198.0	2.074	9.09	2.55E-04	lb/1000 lb coke burned	9.63E-03	4.22E-02	1.00E-06	lb/1000 lb coke burned	3.77E-05	1.65E-04	3.51E-06	lb/1000 lb coke burned	1.32E-04	5.80E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Baseline year NO_X and SO_2 concentrations have adjusted downward equal to the concentration limits from Consent Decree 4th Amendment.
4. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must on a 0% O_2 basis. For CO, the CO concentrations are corrected to 0% O_2 in the tpy calculation. For NO_X and SO_2, the ppm values do not need an additional correction to 0% O_2 since the consent decree limits, which are already on a 0% O@ basis, are used.

Table C.66. 2000 Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	30.80	10^6 bbl/yr	84.4	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	11.6	50.8
FCU 600	19.99	10^6 bbl/yr	54.8	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	7.5	33.0

Process Unit	Usage		Excess Oxygen	$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
				EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	469,214	1000 lb coke burned/yr	1.8%	0.465	lb/1000 lb coke burned	24.9	109.1	26	PPM @ 1.8% excess O2	16.0	69.9	40	PPM @ 0% excess O_2	36.9	161.5	25	PPM @ 0% excess O_2	32.1	140.5	1.472	6.45	2.55E-04	lb/1000 lb coke burned	1.37E-02	5.98E-02	1.00E-06	lb/1000 lb coke burned	5.36E-05	2.35E-04	3.51E-06	lb/1000 lb coke burned	1.88E-04	8.23E-04
FCU 600	330,454	1000 lb coke burned/yr	1.6%	0.350	lb/1000 lb coke burned	13.2	57.8	22	PPM @ 1.6% excess O2	9.4	41.2	20	PPM @ 0% excess O_2	13.0	56.9	50	PPM @ 0% excess O_2	45.2	197.8	2.073	9.08	2.55E-04	lb/1000 lb coke burned	9.62E-03	4.21E-02	1.00E-06	lb/1000 lb coke burned	3.77E-05	1.65E-04	3.51E-06	lb/1000 lb coke burned	1.32E-04	5.80E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Baseline year NO_X and SO_2 concentrations have adjusted downward equal to the concentration limits from Consent Decree 4th Amendment.
4. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must on a 0% O_2 basis. For CO, the CO concentrations are corrected to 0% O_2 in the tpy calculation. For NO_X and SO_2, the ppm values do not need an additional correction to 0% O_2 since the consent decree limits, which are already on a 0% O@ basis, are used.

Table C.67. 2001 Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	31.42	10^6 bbl/yr	86.1	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	11.8	51.8
FCU 600	19.96	10^6 bbl/yr	54.7	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	7.5	32.9

Process Unit	Usage		Excess Oxygen	$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
				EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	477,421	1000 lb coke burned/yr	2.3%	0.465	lb/1000 lb coke burned	25.3	111.0	26	PPM @ 2.3% excess O2	16.7	73.1	40	PPM @ 0% excess O_2	37.5	164.4	25	PPM @ 0% excess O_2	32.6	142.9	1.498	6.56	2.55E-04	lb/1000 lb coke burned	1.39E-02	6.09E-02	1.00E-06	lb/1000 lb coke burned	5.45E-05	2.39E-04	3.51E-06	lb/1000 lb coke burned	1.91E-04	8.38E-04
FCU 600	329,851	1000 lb coke burned/yr	1.7%	0.350	lb/1000 lb coke burned	13.2	57.7	22	PPM @ 1.7% excess O2	9.5	41.4	20	PPM @ 0% excess O_2	13.0	56.8	50	PPM @ 0% excess O_2	45.1	197.5	2.069	9.06	2.55E-04	lb/1000 lb coke burned	9.60E-03	4.21E-02	1.00E-06	lb/1000 lb coke burned	3.77E-05	1.65E-04	3.51E-06	lb/1000 lb coke burned	1.32E-04	5.79E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Baseline year NO_X and SO_2 concentrations have adjusted downward equal to the concentration limits from Consent Decree 4th Amendment.
4. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must on a 0% O_2 basis. For CO, the CO concentrations are corrected to 0% O_2 in the tpy calculation. For NO_X and SO_2, the ppm values do not need an additional correction to 0% O_2 since the consent decree limits, which are already on a 0% O@ basis, are used.

Table C.68. 2002 Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	34.77	10^6 bbl/yr	95.3	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	13.1	57.4
FCU 600	20.70	10^6 bbl/yr	56.7	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	7.8	34.1

Process Unit	Usage		Excess Oxygen	$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
				EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	530,789	1000 lb coke burned/yr	1.5%	0.465	lb/1000 lb coke burned	28.2	123.4	20	PPM @ 1.5% excess O2	13.7	59.9	40	PPM @ 0% excess O_2	41.7	182.7	25	PPM @ 0% excess O_2	36.3	158.9	1.665	7.29	2.55E-04	lb/1000 lb coke burned	1.55E-02	6.77E-02	1.00E-06	lb/1000 lb coke burned	6.06E-05	2.65E-04	3.51E-06	lb/1000 lb coke burned	2.13E-04	9.32E-04
FCU 600	313,311	1000 lb coke burned/yr	1.4%	0.350	lb/1000 lb coke burned	12.5	54.8	14	PPM @ 1.4% excess O2	5.6	24.6	20	PPM @ 0% excess O_2	12.3	53.9	50	PPM @ 0% excess O_2	42.8	187.6	1.966	8.61	2.55E-04	lb/1000 lb coke burned	9.12E-03	3.99E-02	1.00E-06	lb/1000 lb coke burned	3.58E-05	1.57E-04	3.51E-06	lb/1000 lb coke burned	1.26E-04	5.50E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Baseline year NO_X and SO_2 concentrations have adjusted downward equal to the concentration limits from Consent Decree 4th Amendment.
4. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must on a 0% O_2 basis. For CO, the CO concentrations are corrected to 0% O_2 in the tpy calculation. For NO_X and SO_2, the ppm values do not need an additional correction to 0% O_2 since the consent decree limits, which are already on a 0% O@ basis, are used.

Table C.69. 2003 Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	30.07	10^6 bbl/yr	82.4	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	11.3	49.6
FCU 600	17.64	10^6 bbl/yr	48.3	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	6.6	29.1

Process Unit	Usage		Excess Oxygen	$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
				EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	450,193	1000 lb coke burned/yr	2.0%	0.465	lb/1000 lb coke burned	23.9	104.7	24	PPM @ 2% excess O2	14.3	62.6	40	PPM @ 0% excess O_2	35.4	155.0	25	PPM @ 0% excess O_2	30.8	134.8	1.412	6.19	2.55E-04	lb/1000 lb coke burned	1.31E-02	5.74E-02	1.00E-06	lb/1000 lb coke burned	5.14E-05	2.25E-04	3.51E-06	lb/1000 lb coke burned	1.80E-04	7.90E-04
FCU 600	308,346	1000 lb coke burned/yr	1.4%	0.350	lb/1000 lb coke burned	12.3	54.0	19	PPM @ 1.4% excess O2	7.5	32.8	20	PPM @ 0% excess O_2	12.1	53.1	50	PPM @ 0% excess O_2	42.1	184.6	1.934	8.47	2.55E-04	lb/1000 lb coke burned	8.98E-03	3.93E-02	1.00E-06	lb/1000 lb coke burned	3.52E-05	1.54E-04	3.51E-06	lb/1000 lb coke burned	1.24E-04	5.41E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Baseline year NO_X and SO_2 concentrations have adjusted downward equal to the concentration limits from Consent Decree 4th Amendment.
4. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must on a 0% O_2 basis. For CO, the CO concentrations are corrected to 0% O_2 in the tpy calculation. For NO_X and SO_2, the ppm values do not need an additional correction to 0% O_2 since the consent decree limits, which are already on a 0% O@ basis, are used.

Table C.70. 2004 Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	32.84	10^6 bbl/yr	90.0	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	12.4	54.2
FCU 600	19.77	10^6 bbl/yr	54.2	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	7.4	32.6

Process Unit	Usage		Excess Oxygen	$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
				EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	494,967	1000 lb coke burned/yr	1.9%	0.465	lb/1000 lb coke burned	26.3	115.1	34	PPM @ 1.9% excess O2	22.2	97.1	40	PPM @ 0% excess O_2	38.9	170.4	25	PPM @ 0% excess O_2	33.8	148.2	1.553	6.80	2.55E-04	lb/1000 lb coke burned	1.44E-02	6.31E-02	1.00E-06	lb/1000 lb coke burned	5.65E-05	2.47E-04	3.51E-06	lb/1000 lb coke burned	1.98E-04	8.69E-04
FCU 600	377,852	1000 lb coke burned/yr	2.1%	0.350	lb/1000 lb coke burned	15.1	66.1	33	PPM @ 2.1% excess O2	16.6	72.6	20	PPM @ 0% excess O_2	14.8	65.0	50	PPM @ 0% excess O_2	51.6	226.2	2.370	10.38	2.55E-04	lb/1000 lb coke burned	1.10E-02	4.82E-02	1.00E-06	lb/1000 lb coke burned	4.31E-05	1.89E-04	3.51E-06	lb/1000 lb coke burned	1.51E-04	6.63E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Baseline year NO_X and SO_2 concentrations have adjusted downward equal to the concentration limits from Consent Decree 4th Amendment.
4. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must on a 0% O_2 basis. For CO, the CO concentrations are corrected to 0% O_2 in the tpy calculation. For NO_X and SO_2, the ppm values do not need an additional correction to 0% O_2 since the consent decree limits, which are already on a 0% O@ basis, are used.

Table C.70a. Historical Reported and Allowable SO_2 Emissions for Fluidized Catalytic Cracking Unit 600

FCU 600 Emissions from Annual Emission Reports (As Reported)

Year	SO_2 (ton/yr)
1999	1,769.9
2000	2,031.9

FCU 600 Estimated SO_2 Allowable Emissions

Allowable Usage[1]				SO_2 Concentration[2]		SO_2 PTE tpy
80	1000 bbl/day	16.7	lb coke burned/ bbl fresh feed	50	PPM @ 0% excess O_2	291.4

Baseline Period	Emissions Reduction (tpy)	10% of Emissions Reduction[3] (tpy)
1999-2000	1,609.5	160.9

1. The FCU 600 Allowable Emissions were calculated using the maximum capacity of 80 (1000 bbl/day) and the ratio of coke burned to fresh feed, which is based on historical FCU 600 usage.
2. The Consent Decree limits FCU 600 to an SO_2 concentration of 50 ppm at 0% excess O_2.
3. Pursuant to the BP Whiting Consent Decree, up to ten percent (10%) of the SO_2 reduction credits generated by the FCU 600 SO_2 emissions reduction to 50 ppm could be used for netting SO_2 emissions increases that result from the construction or modification of "netting/offset generating units".

Table C.71. Existing Unit Volatile Organic Compound Emissions

Process Unit	Operating Rate					VOC						
						Future		Baseline		Calculation Cells		
	Future		Baseline Emissions (2001-2002)		Difference	EF	Unit	EF	Unit	Future	Baseline	tpy[1]
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	124.79	MMBtu/hr	49.11	0.0054	lb/MMBtu	0.0054	lb/MMBtu	4.1	2.9	1.2
H-2	32.3	MMBtu/hr	27.59	MMBtu/hr	4.71	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.8	0.7	0.1
H-3	49.2	MMBtu/hr	41.75	MMBtu/hr	7.45	0.0054	lb/MMBtu	0.0054	lb/MMBtu	1.16	0.99	0.2
11C PS												
H-200	182.8	MMBtu/hr	157.60	MMBtu/hr	25.20	0.0054	lb/MMBtu	0.0054	lb/MMBtu	4.3	3.7	0.6
H-300	72.0	MMBtu/hr	82.79	MMBtu/hr	-10.79	0.0054	lb/MMBtu	0.0054	lb/MMBtu	1.7	2.0	-0.3
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	38.66	MMBtu/hr	-9.06	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.7	0.9	-0.2
F-8A	142.3	MMBtu/hr	91.61	MMBtu/hr	50.69	0.0054	lb/MMBtu	0.0054	lb/MMBtu	3.4	2.2	1.2
F-8B	142.3	MMBtu/hr	88.62	MMBtu/hr	53.68	0.0054	lb/MMBtu	0.0054	lb/MMBtu	3.4	2.1	1.3
F-2	169.9	MMBtu/hr	206.97	MMBtu/hr	-37.07	0.0054	lb/MMBtu	0.0054	lb/MMBtu	4.0	4.9	-0.9
F-3	180.0	MMBtu/hr	177.52	MMBtu/hr	2.48	0.0054	lb/MMBtu	0.0054	lb/MMBtu	4.3	4.2	0.1
F-4	96.8	MMBtu/hr	112.22	MMBtu/hr	-15.42	0.0054	lb/MMBtu	0.0054	lb/MMBtu	2.3	2.7	-0.4
F-5	48.8	MMBtu/hr	58.38	MMBtu/hr	-9.58	0.0054	lb/MMBtu	0.0054	lb/MMBtu	1.2	1.4	-0.2
F-6	21.7	MMBtu/hr	28.71	MMBtu/hr	-7.01	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.5	0.7	-0.2
F-7	36.2	MMBtu/hr	35.21	MMBtu/hr	0.99	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.9	0.8	0.0
Regen[2]										1.7	1.2	0.5
Fugitives												0.3
ARU												
F-200A	144.4	MMBtu/hr	132.16	MMBtu/hr	12.24	0.0054	lb/MMBtu	0.0054	lb/MMBtu	3.4	3.1	0.3
F-200B	144.4	MMBtu/hr	140.99	MMBtu/hr	3.41	0.0054	lb/MMBtu	0.0054	lb/MMBtu	3.4	3.3	0.1
BOU												
F-401	23.0	MMBtu/hr	13.80	MMBtu/hr	9.20	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.5	0.3	0.2
CFHU												
F-801A	24.6	MMBtu/hr	16.59	MMBtu/hr	8.01	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.6	0.4	0.2
F-801B	24.6	MMBtu/hr	15.76	MMBtu/hr	8.84	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.6	0.4	0.2
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.60	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.6	0.0	0.6
CRU												
F-101	23.8	MMBtu/hr	28.80	MMBtu/hr	-5.00	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.6	0.7	-0.1
F-102	23.8	MMBtu/hr	15.00	MMBtu/hr	8.80	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.6	0.4	0.2
DDU												
WB-301	70.8	MMBtu/hr	26.35	MMBtu/hr	44.45	0.0054	lb/MMBtu	0.0054	lb/MMBtu	1.7	0.6	1.0
WB-302	55.8	MMBtu/hr	60.54	MMBtu/hr	-4.74	0.0054	lb/MMBtu	0.0054	lb/MMBtu	1.3	1.4	-0.1
ISOM												
H-1	153.2	MMBtu/hr	154.70	MMBtu/hr	-1.50	0.0054	lb/MMBtu	0.0054	lb/MMBtu	3.6	3.7	0.0
HU												
B-501	320.7	MMBtu/hr	167.81	MMBtu/hr	152.89	0.0054	lb/MMBtu	0.0054	lb/MMBtu	7.6	4.0	3.6
Fluidized Catalytic Cracking												
FCU 500	103	1000 bbl/day	90.7	1000 bbl/day	12.33	220	lb/1000 bbl	220	lb/1000 bbl	62.0	54.6	7.4
FCU 600	66	1000 bbl/day	55.7	1000 bbl/day	10.31	220	lb/1000 bbl	220	lb/1000 bbl	39.7	33.5	6.2

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

[2] 4UF Reformer Regen emissions based on data recorded by BP Whiting PI data collection system.

Table C.72. Existing Unit Nitrogen Oxide Emissions

Process Unit	Operating Rate					NOx						
	Future		Baseline Emissions (1999-2000)		Difference	Future		Baseline		Calculation Cells		tpy[1]
						EF	Unit	EF	Unit	Future	Baseline	
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	138.50	MMBtu/hr	35.40	0.166	lb/MMBtu	0.166	lb/MMBtu	126.4	100.7	25.7
H-2	32.3	MMBtu/hr	20.71	MMBtu/hr	11.59	0.098	lb/MMBtu	0.098	lb/MMBtu	13.9	8.9	5.0
H-3	49.2	MMBtu/hr	33.30	MMBtu/hr	15.90	0.098	lb/MMBtu	0.098	lb/MMBtu	21.1	14.3	6.8
11C PS												
H-200[2]	182.8	MMBtu/hr	92.67	MMBtu/hr	90.13	0.05	lb/MMBtu	0.275	lb/MMBtu	40.0	111.4	-71.4
H-300	72.0	MMBtu/hr	79.03	MMBtu/hr	-7.03	0.137	lb/MMBtu	0.137	lb/MMBtu	43.3	47.5	-4.2
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	37.97	MMBtu/hr	-8.37	0.098	lb/MMBtu	0.098	lb/MMBtu	12.7	16.3	-3.6
F-8A	142.3	MMBtu/hr	98.57	MMBtu/hr	43.73	0.275	lb/MMBtu	0.275	lb/MMBtu	171.1	118.5	52.6
F-8B	142.3	MMBtu/hr	92.86	MMBtu/hr	49.44	0.275	lb/MMBtu	0.275	lb/MMBtu	171.1	111.7	59.4
F-2	169.9	MMBtu/hr	225.75	MMBtu/hr	-55.85	0.186	lb/MMBtu	0.186	lb/MMBtu	138.6	184.2	-45.6
F-3	180.0	MMBtu/hr	201.41	MMBtu/hr	-21.41	0.275	lb/MMBtu	0.275	lb/MMBtu	216.4	242.2	-25.7
F-4	96.8	MMBtu/hr	121.15	MMBtu/hr	-24.35	0.275	lb/MMBtu	0.275	lb/MMBtu	116.4	145.7	-29.3
F-5	48.8	MMBtu/hr	44.02	MMBtu/hr	4.78	0.098	lb/MMBtu	0.098	lb/MMBtu	21.0	18.9	2.1
F-6	21.7	MMBtu/hr	40.13	MMBtu/hr	-18.43	0.098	lb/MMBtu	0.098	lb/MMBtu	9.3	17.2	-7.9
F-7	36.2	MMBtu/hr	31.56	MMBtu/hr	4.64	0.098	lb/MMBtu	0.098	lb/MMBtu	15.5	13.6	2.0
Regen												
ARU												
F-200A	144.4	MMBtu/hr	165.01	MMBtu/hr	-20.61	0.275	lb/MMBtu	0.275	lb/MMBtu	173.6	198.4	-24.8
F-200B	144.4	MMBtu/hr	170.06	MMBtu/hr	-25.66	0.275	lb/MMBtu	0.275	lb/MMBtu	173.6	204.5	-30.8
BOU												
F-401	23.0	MMBtu/hr	15.19	MMBtu/hr	7.81	0.098	lb/MMBtu	0.098	lb/MMBtu	9.9	6.5	3.4
CFHU												
F-801A	24.6	MMBtu/hr	11.22	MMBtu/hr	13.38	0.049	lb/MMBtu	0.049	lb/MMBtu	5.3	2.4	2.9
F-801B	24.6	MMBtu/hr	11.22	MMBtu/hr	13.38	0.049	lb/MMBtu	0.049	lb/MMBtu	5.3	2.4	2.9
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.60	0.036	lb/MMBtu	0.036	lb/MMBtu	3.9	0.0	3.9
CRU												
F-101	23.8	MMBtu/hr	43.87	MMBtu/hr	-20.07	0.080	lb/MMBtu	0.080	lb/MMBtu	8.3	15.4	-7.0
F-102	23.8	MMBtu/hr	22.17	MMBtu/hr	1.63	0.080	lb/MMBtu	0.080	lb/MMBtu	8.3	7.8	0.6
DDU												
WB-301	70.8	MMBtu/hr	37.98	MMBtu/hr	32.82	0.035	lb/MMBtu	0.035	lb/MMBtu	10.7	5.8	5.0
WB-302	55.8	MMBtu/hr	61.91	MMBtu/hr	-6.11	0.030	lb/MMBtu	0.030	lb/MMBtu	7.3	8.1	-0.8
ISOM												
H-1	153.2	MMBtu/hr	180.24	MMBtu/hr	-27.04	0.275	lb/MMBtu	0.275	lb/MMBtu	184.2	216.7	-32.5
HU												
B-501	320.7	MMBtu/hr	179.01	MMBtu/hr	141.69	0.068	lb/MMBtu	0.068	lb/MMBtu	94.8	52.9	41.9
Fluidized Catalytic Cracking												
FCU 500	103	1000 bbl/day	81.2	1000 bbl/day	21.8	37.9	PPM	40	PPM	228.6	155.2	73.4
	669,191	1000 lb coke burned/yr	450,968	1000 lb coke burned/yr	218,223							
FCU 600	66	1000 bbl/day	57.1	1000 bbl/day	8.9	20	PPM	20	PPM	73.8	56.9	16.9
	428,802	1000 lb coke burned/yr	330,554	1000 lb coke burned/yr	98,248							

1. Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.
2. As part of the CXHO project, BP Whiting will be installing Ultra-Low NOX burners on heater 11C PS H-200 to generate creditable emission reductions.

Table C.73. Existing Unit Sulfur Dioxide Emissions

Process Unit	Operating Rate					SO_2						
			Baseline Emissions			Future		Baseline		Calculation Cells		
	Future		(2003-2004)		Difference	EF	Unit	EF	Unit	Future[2]	Baseline	tpy[1]
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	146.85	MMBtu/hr	27.1	0.0111	lb/MMBtu	0.0218	lb/MMBtu	8.4	14.0	-5.6
H-2	32.3	MMBtu/hr	21.34	MMBtu/hr	11.0	0.0111	lb/MMBtu	0.0218	lb/MMBtu	1.6	2.0	-0.5
H-3	49.2	MMBtu/hr	40.64	MMBtu/hr	8.6	0.0111	lb/MMBtu	0.0218	lb/MMBtu	2.4	3.9	-1.5
11C PS												
H-200	182.8	MMBtu/hr	99.13	MMBtu/hr	83.7	0.0111	lb/MMBtu	0.0218	lb/MMBtu	8.9	9.4	-0.6
H-300	72.0	MMBtu/hr	74.35	MMBtu/hr	-2.4	0.0111	lb/MMBtu	0.0218	lb/MMBtu	3.5	7.1	-3.6
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	36.17	MMBtu/hr	-6.6	0.0111	lb/MMBtu	0.0066	lb/MMBtu	1.4	1.0	0.4
F-8A	142.3	MMBtu/hr	70.64	MMBtu/hr	71.7	0.0111	lb/MMBtu	0.0066	lb/MMBtu	6.9	2.0	4.8
F-8B	142.3	MMBtu/hr	67.05	MMBtu/hr	75.3	0.0111	lb/MMBtu	0.0066	lb/MMBtu	6.9	1.9	4.9
F-2	169.9	MMBtu/hr	189.00	MMBtu/hr	-19.1	0.0111	lb/MMBtu	0.0066	lb/MMBtu	8.2	5.5	2.7
F-3	180.0	MMBtu/hr	164.04	MMBtu/hr	16.0	0.0111	lb/MMBtu	0.0066	lb/MMBtu	8.7	4.8	4.0
F-4	96.8	MMBtu/hr	90.74	MMBtu/hr	6.1	0.0111	lb/MMBtu	0.0066	lb/MMBtu	4.7	2.6	2.1
F-5	48.8	MMBtu/hr	47.35	MMBtu/hr	1.4	0.0111	lb/MMBtu	0.0066	lb/MMBtu	2.4	1.4	1.0
F-6	21.7	MMBtu/hr	32.40	MMBtu/hr	-10.7	0.0111	lb/MMBtu	0.0066	lb/MMBtu	1.1	0.9	0.1
F-7	36.2	MMBtu/hr	32.25	MMBtu/hr	4.0	0.0111	lb/MMBtu	0.0066	lb/MMBtu	1.8	0.9	0.8
Regen[3]										3.5	2.5	1.0
ARU												
F-200A	144.4	MMBtu/hr	170.57	MMBtu/hr	-26.2	0.0111	lb/MMBtu	0.0218	lb/MMBtu	7.0	16.3	-9.3
F-200B	144.4	MMBtu/hr	163.37	MMBtu/hr	-19.0	0.0111	lb/MMBtu	0.0218	lb/MMBtu	7.0	15.6	-8.6
BOU												
F-401	23.0	MMBtu/hr	11.29	MMBtu/hr	11.7	0.0111	lb/MMBtu	0.0066	lb/MMBtu	1.1	0.3	0.8
CFHU												
F-801A	24.6	MMBtu/hr	9.99	MMBtu/hr	14.6	0.0111	lb/MMBtu	0.0086	lb/MMBtu	1.2	0.4	0.8
F-801B	24.6	MMBtu/hr	10.17	MMBtu/hr	14.4	0.0111	lb/MMBtu	0.0086	lb/MMBtu	1.2	0.4	0.8
F-801C	24.6	MMBtu/hr	0.30	MMBtu/hr	24.3	0.0111	lb/MMBtu	0.0086	lb/MMBtu	1.2	0.0	1.2
CRU												
F-101	23.8	MMBtu/hr	20.98	MMBtu/hr	2.8	0.0111	lb/MMBtu	0.0065	lb/MMBtu	1.2	0.6	0.6
F-102	23.8	MMBtu/hr	21.51	MMBtu/hr	2.3	0.0111	lb/MMBtu	0.0065	lb/MMBtu	1.2	0.6	0.5
DDU												
WB-301	70.8	MMBtu/hr	36.40	MMBtu/hr	34.4	0.0111	lb/MMBtu	0.0218	lb/MMBtu	3.4	3.5	0.0
WB-302	55.8	MMBtu/hr	50.19	MMBtu/hr	5.6	0.0111	lb/MMBtu	0.0218	lb/MMBtu	2.7	4.8	-2.1
ISOM												
H-1	153.2	MMBtu/hr	135.21	MMBtu/hr	18.0	0.0111	lb/MMBtu	0.0218	lb/MMBtu	7.4	12.9	-5.5
HU												
B-501	320.7	MMBtu/hr	168.83	MMBtu/hr	151.9	0.0111	lb/MMBtu	0.0708	lb/MMBtu	15.5	52.3	-36.8
Fluidized Catalytic Cracking												
FCU 500	103	1000 bbl/day	86.2	1000 bbl/day	16.8	25	PPM	25	PPM	200.3	141.5	58.9
	669,191	1000 lb coke burned/yr	472,580	1000 lb coke burned/yr	196,611							
FCU 600	66	1000 bbl/day	51.2	1000 bbl/day	14.8	37	PPM	50	PPM	190.0	205.4	-15.4
	428,802	1000 lb coke burned/yr	343,099	1000 bbl/day	85,703							

1. Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.
2. Calculation accounts for annual average design refinery fuel gas higher heating value of 1,203 Btu/scf.
3. 4UF Reformer Regen emissions based on data recorded by BP Whiting PI data collection system.

Table C.74. Existing Unit PM (Filterable) Emissions

Process Unit	Operating Rate					PM						
			Baseline Emissions (2001-2002)		Difference	Future		Baseline		Calculation Cells		tpy[1]
	Future					EF	Unit	EF	Unit	Future	Baseline	
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	124.79	MMBtu/hr	49.11	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.4	1.0	0.4
H-2	32.3	MMBtu/hr	27.59	MMBtu/hr	4.71	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.3	0.2	0.0
H-3	49.2	MMBtu/hr	41.75	MMBtu/hr	7.45	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.4	0.3	0.1
11C PS												
H-200	182.8	MMBtu/hr	157.60	MMBtu/hr	25.20	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.5	1.3	0.2
H-300	72.0	MMBtu/hr	82.79	MMBtu/hr	-10.79	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.6	0.7	-0.1
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	38.66	MMBtu/hr	-9.06	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.3	-0.1
F-8A	142.3	MMBtu/hr	91.61	MMBtu/hr	50.69	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.2	0.7	0.4
F-8B	142.3	MMBtu/hr	88.62	MMBtu/hr	53.68	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.2	0.7	0.4
F-2	169.9	MMBtu/hr	206.97	MMBtu/hr	-37.07	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.4	1.7	-0.3
F-3	180.0	MMBtu/hr	177.52	MMBtu/hr	2.48	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.5	1.4	0.0
F-4	96.8	MMBtu/hr	112.22	MMBtu/hr	-15.42	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.8	0.9	-0.1
F-5	48.8	MMBtu/hr	58.38	MMBtu/hr	-9.58	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.4	0.5	-0.1
F-6	21.7	MMBtu/hr	28.71	MMBtu/hr	-7.01	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.2	-0.1
F-7	36.2	MMBtu/hr	35.21	MMBtu/hr	0.99	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.3	0.3	0.0
Regen												
ARU												
F-200A	144.4	MMBtu/hr	132.16	MMBtu/hr	12.24	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.2	1.1	0.1
F-200B	144.4	MMBtu/hr	140.99	MMBtu/hr	3.41	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.2	1.2	0.0
BOU												
F-401	23.0	MMBtu/hr	13.80	MMBtu/hr	9.20	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.1	0.1
CFHU												
F-801A	24.6	MMBtu/hr	16.59	MMBtu/hr	8.01	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.1	0.1
F-801B	24.6	MMBtu/hr	15.76	MMBtu/hr	8.84	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.1	0.1
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.60	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.0	0.2
CRU												
F-101	23.8	MMBtu/hr	28.80	MMBtu/hr	-5.00	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.2	0.0
F-102	23.8	MMBtu/hr	15.00	MMBtu/hr	8.80	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.1	0.1
DDU												
WB-301	70.8	MMBtu/hr	26.35	MMBtu/hr	44.45	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.6	0.2	0.4
WB-302	55.8	MMBtu/hr	60.54	MMBtu/hr	-4.74	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.5	0.5	0.0
ISOM												
H-1	153.2	MMBtu/hr	154.70	MMBtu/hr	-1.50	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.2	1.3	0.0
HU												
B-501	320.7	MMBtu/hr	167.81	MMBtu/hr	152.89	0.0019	lb/MMBtu	0.0019	lb/MMBtu	2.6	1.4	1.2
Fluidized Catalytic Cracking												
FCU 500	103	1000 bbl/day	90.7	1000 bbl/day	12.3	0.465	lb/1000 lb coke burned	0.465	lb/1000 lb coke burned	155.6	117.2	38.4
	669,191	1000 lb coke burned/yr	504,105	1000 lb coke burned/yr	165,086							
FCU 600	66	1000 bbl/day	55.7	1000 bbl/day	10.3	0.35	lb/1000 lb coke burned	0.35	lb/1000 lb coke burned	75.0	56.3	18.8
	428,802	1000 lb coke burned/yr	321,581	1000 lb coke burned/yr	107,221							

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

Table C.75. Existing Unit $PM_{10}/PM_{2.5}$ (Filterable + Condensable) Emissions

Process Unit	Operating Rate					$PM_{10}/PM_{2.5}$						
			Baseline Emissions			Future		Baseline[2]		Calculation Cells		
	Future		(2001-2002)		Difference	EF	Unit	EF	Unit	Future	Baseline	tpy[1]
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	124.79	MMBtu/hr	49.11	0.0075	lb/MMBtu	0.0075	lb/MMBtu	5.7	4.1	1.6
H-2	32.3	MMBtu/hr	27.59	MMBtu/hr	4.71	0.0075	lb/MMBtu	0.0075	lb/MMBtu	1.1	0.9	0.2
H-3	49.2	MMBtu/hr	41.75	MMBtu/hr	7.45	0.0075	lb/MMBtu	0.0075	lb/MMBtu	1.6	1.4	0.2
11C PS												
H-200	182.8	MMBtu/hr	157.60	MMBtu/hr	25.20	0.0075	lb/MMBtu	0.0075	lb/MMBtu	6.0	5.1	0.8
H-300	72.0	MMBtu/hr	82.79	MMBtu/hr	-10.79	0.0075	lb/MMBtu	0.0075	lb/MMBtu	2.3	2.7	-0.4
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	38.66	MMBtu/hr	-9.06	0.0075	lb/MMBtu	0.004	lb/MMBtu	1.0	0.7	0.3
F-8A	142.3	MMBtu/hr	91.61	MMBtu/hr	50.69	0.0075	lb/MMBtu	0.004	lb/MMBtu	4.6	1.6	3.0
F-8B	142.3	MMBtu/hr	88.62	MMBtu/hr	53.68	0.0075	lb/MMBtu	0.004	lb/MMBtu	4.6	1.6	3.1
F-2	169.9	MMBtu/hr	206.97	MMBtu/hr	-37.07	0.0075	lb/MMBtu	0.004	lb/MMBtu	5.5	3.6	1.9
F-3	180.0	MMBtu/hr	177.52	MMBtu/hr	2.48	0.0075	lb/MMBtu	0.004	lb/MMBtu	5.9	3.1	2.8
F-4	96.8	MMBtu/hr	112.22	MMBtu/hr	-15.42	0.0075	lb/MMBtu	0.004	lb/MMBtu	3.2	2.0	1.2
F-5	48.8	MMBtu/hr	58.38	MMBtu/hr	-9.58	0.0075	lb/MMBtu	0.004	lb/MMBtu	1.6	1.0	0.6
F-6	21.7	MMBtu/hr	28.71	MMBtu/hr	-7.01	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.7	0.5	0.2
F-7	36.2	MMBtu/hr	35.21	MMBtu/hr	0.99	0.0075	lb/MMBtu	0.004	lb/MMBtu	1.2	0.6	0.6
Regen												
ARU												
F-200A	144.4	MMBtu/hr	132.16	MMBtu/hr	12.24	0.0075	lb/MMBtu	0.004	lb/MMBtu	4.7	2.3	2.4
F-200B	144.4	MMBtu/hr	140.99	MMBtu/hr	3.41	0.0075	lb/MMBtu	0.004	lb/MMBtu	4.7	2.5	2.2
BOU												
F-401	23.0	MMBtu/hr	13.80	MMBtu/hr	9.20	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.8	0.2	0.5
CFHU												
F-801A	24.6	MMBtu/hr	16.59	MMBtu/hr	8.01	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.8	0.3	0.5
F-801B	24.6	MMBtu/hr	15.76	MMBtu/hr	8.84	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.8	0.3	0.5
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.60	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.8	0.0	0.8
CRU												
F-101	23.8	MMBtu/hr	28.80	MMBtu/hr	-5.00	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.8	0.5	0.3
F-102	23.8	MMBtu/hr	15.00	MMBtu/hr	8.80	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.8	0.3	0.5
DDU												
WB-301	70.8	MMBtu/hr	26.35	MMBtu/hr	44.45	0.0075	lb/MMBtu	0.004	lb/MMBtu	2.3	0.5	1.8
WB-302	55.8	MMBtu/hr	60.54	MMBtu/hr	-4.74	0.0075	lb/MMBtu	0.004	lb/MMBtu	1.8	1.1	0.8
ISOM												
H-1	153.2	MMBtu/hr	154.70	MMBtu/hr	-1.50	0.0075	lb/MMBtu	0.004	lb/MMBtu	5.0	2.7	2.3
HU												
B-501	320.7	MMBtu/hr	167.81	MMBtu/hr	152.89	0.0075	lb/MMBtu	0.0075	lb/MMBtu	10.5	5.5	5.0
Fluidized Catalytic Cracking												
FCU 500	103	1000 bbl/day	90.7	1000 bbl/day	12.3	0.465	lb/1000 lb coke burned	0.465	1000 lb coke burned/yr	155.6	117.2	38.4
	669,191	1000 lb coke burned/yr	504,105	1000 lb coke burned/yr	165,086							
FCU 600	66	1000 bbl/day	55.7	1000 bbl/day	10.3	0.35	lb/1000 lb coke burned	0.35	1000 lb coke burned/yr	75.0	56.3	18.8
	428,802	1000 lb coke burned/yr	321,581	1000 lb coke burned/yr	107,221							

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

[2] Based on interim guidance from US EPA, $PM_{2.5}$ is evaluated based on significant emission rate thresholds established for PM_{10}. The current PM_{10} SIP limits filterable PM_{10} emissions and compliance is based on reference test method 201A (which only quantifies filterable particulate matter). Although not required, BP Whiting has conservatively adjusted the PM10 baseline based on the PM_{10} SIP limits for PSD applicability purposes, which includes both filterable and condensable PM_{10}. $PM_{2.5}$ emissions are not regula by the Lake County PM10 SIP, however, to be conservative, BP Whiting has adjusted $PM_{2.5}$ baseline emissions in the same manner as for PM_{10} emissions.

Table C.76. Existing Unit Carbon Monoxide Emissions

Process Unit	Operating Rate					CO						
	Future		Baseline Emissions (1999-2000)		Difference	Future		Baseline		Calculation Cells		tpy[1]
						EF	Unit	EF	Unit	Future	Baseline	
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	138.50	MMBtu/hr	35.40	0.0824	lb/MMBtu	0.0824	lb/MMBtu	62.7	50.0	12.8
H-2	32.3	MMBtu/hr	20.71	MMBtu/hr	11.59	0.0824	lb/MMBtu	0.0824	lb/MMBtu	11.7	7.5	4.2
H-3	49.2	MMBtu/hr	33.30	MMBtu/hr	15.90	0.0824	lb/MMBtu	0.082	lb/MMBtu	17.7	12.0	5.7
11C PS												
H-200	182.8	MMBtu/hr	92.67	MMBtu/hr	90.13	0.0824	lb/MMBtu	0.082	lb/MMBtu	65.9	33.4	32.5
H-300	72.0	MMBtu/hr	79.03	MMBtu/hr	-7.03	0.0824	lb/MMBtu	0.082	lb/MMBtu	26.0	28.5	-2.5
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	37.97	MMBtu/hr	-8.37	0.0824	lb/MMBtu	0.082	lb/MMBtu	10.7	13.7	-3.0
F-8A	142.3	MMBtu/hr	98.57	MMBtu/hr	43.73	0.0824	lb/MMBtu	0.082	lb/MMBtu	51.3	35.6	15.8
F-8B	142.3	MMBtu/hr	92.86	MMBtu/hr	49.44	0.0824	lb/MMBtu	0.082	lb/MMBtu	51.3	33.0	18.3
F-2	169.9	MMBtu/hr	225.75	MMBtu/hr	-55.85	0.0824	lb/MMBtu	0.082	lb/MMBtu	61.3	81.4	-20.1
F-3	180.0	MMBtu/hr	201.41	MMBtu/hr	-21.41	0.0824	lb/MMBtu	0.082	lb/MMBtu	64.9	72.7	-7.7
F-4	96.8	MMBtu/hr	121.15	MMBtu/hr	-24.35	0.0824	lb/MMBtu	0.082	lb/MMBtu	34.9	43.7	-8.8
F-5	48.8	MMBtu/hr	44.02	MMBtu/hr	4.78	0.0824	lb/MMBtu	0.082	lb/MMBtu	17.6	15.9	1.7
F-6	21.7	MMBtu/hr	40.13	MMBtu/hr	-18.43	0.0824	lb/MMBtu	0.082	lb/MMBtu	7.8	14.5	-6.6
F-7	36.2	MMBtu/hr	31.56	MMBtu/hr	4.64	0.0824	lb/MMBtu	0.082	lb/MMBtu	13.1	11.4	1.7
Regen[2]										11.1	8.0	3.2
ARU												
F-200A	144.4	MMBtu/hr	165.01	MMBtu/hr	-20.61	0.0824	lb/MMBtu	0.082	lb/MMBtu	52.1	59.5	-7.4
F-200B	144.4	MMBtu/hr	170.06	MMBtu/hr	-25.66	0.0824	lb/MMBtu	0.082	lb/MMBtu	52.1	61.3	-9.3
BOU												
F-401	23.0	MMBtu/hr	15.19	MMBtu/hr	7.81	0.0824	lb/MMBtu	0.082	lb/MMBtu	8.3	5.5	2.8
CFHU												
F-801A	24.6	MMBtu/hr	11.22	MMBtu/hr	13.38	0.0824	lb/MMBtu	0.082	lb/MMBtu	8.9	4.0	4.8
F-801B	24.6	MMBtu/hr	11.22	MMBtu/hr	13.38	0.0824	lb/MMBtu	0.082	lb/MMBtu	8.9	4.0	4.8
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.60	0.0001	lb/MMBtu	0.0001	lb/MMBtu	0.0	0.0	0.0
CRU												
F-101	23.8	MMBtu/hr	43.87	MMBtu/hr	-20.07	0.0824	lb/MMBtu	0.0824	lb/MMBtu	8.6	15.8	-7.2
F-102	23.8	MMBtu/hr	22.17	MMBtu/hr	1.63	0.0824	lb/MMBtu	0.0824	lb/MMBtu	8.6	8.0	0.6
DDU												
WB-301	70.8	MMBtu/hr	37.98	MMBtu/hr	32.82	0.0400	lb/MMBtu	0.04	lb/MMBtu	12.4	6.7	5.7
WB-302	55.8	MMBtu/hr	61.91	MMBtu/hr	-6.11	0.0400	lb/MMBtu	0.04	lb/MMBtu	9.8	10.8	-1.1
ISOM												
H-1	153.2	MMBtu/hr	180.24	MMBtu/hr	-27.04	0.0824	lb/MMBtu	0.082	lb/MMBtu	55.3	65.0	-9.8
HU												
B-501	320.7	MMBtu/hr	179.01	MMBtu/hr	141.69	0.02	lb/MMBtu	0.02	lb/MMBtu	28.1	15.7	12.4
Fluidized Catalytic Cracking												
FCU 500	103	1000 bbl/day	81.2	1000 bbl/day	21.8	42	PPM	26	PPM	147.2	67.4	79.9
	669,191	1000 lb coke burned/yr	450,968	1000 lb coke burned/yr	218,223							
FCU 600	66	1000 bbl/day	57.1	1000 bbl/day	8.9	41	PPM	22	PPM	92.1	41.0	51.1
	428,802	1000 lb coke burned/yr	330,554	1000 lb coke burned/yr	98,248							

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.
[2] 4UF Reformer Regen emissions based on data recorded by BP Whiting PI data collection system.

Table C.77. Existing Unit Sulfuric Acid Mist Emissions

Process Unit	SO_2 Emissions					H_2SO_4 Mist		
	Future		Baseline Emissions (2003-2004)		Difference	Calculation Cells		tpy[1]
						Future	Baseline	
Crude and Coking								
11A PS								
H-1X	8.4	tpy	14.0	tpy	-5.57	0.39	0.64	-0.26
H-2	1.6	tpy	2.0	tpy	-0.47	0.07	0.09	-0.02
H-3	2.4	tpy	3.9	tpy	-1.49	0.11	0.18	-0.07
11C PS								
H-200	8.9	tpy	9.4	tpy	-0.59	0.41	0.43	-0.03
H-300	3.5	tpy	7.1	tpy	-3.60	0.16	0.33	-0.17
Hydroprocessing								
4UF								
F-1	1.4	tpy	1.0	tpy	0.39	0.07	0.05	0.02
F-8A	6.9	tpy	2.0	tpy	4.84	0.32	0.09	0.22
F-8B	6.9	tpy	1.9	tpy	4.95	0.32	0.09	0.23
F-2	8.2	tpy	5.5	tpy	2.75	0.38	0.25	0.13
F-3	8.7	tpy	4.8	tpy	3.96	0.40	0.22	0.18
F-4	4.7	tpy	2.6	tpy	2.06	0.22	0.12	0.09
F-5	2.4	tpy	1.4	tpy	0.99	0.11	0.06	0.05
F-6	1.1	tpy	0.9	tpy	0.11	0.05	0.04	0.01
F-7	1.8	tpy	0.9	tpy	0.82	0.08	0.04	0.04
Regen[2]	3.5	tpy	2.5	tpy	0.98	0.16	0.11	0.05
ARU								
F-200A	7.0	tpy	16.3	tpy	-9.26	0.32	0.75	-0.42
F-200B	7.0	tpy	15.6	tpy	-8.57	0.32	0.71	-0.39
BOU								
F-401	1.1	tpy	0.3	tpy	0.79	0.05	0.02	0.04
CFHU								
F-801A	1.2	tpy	0.4	tpy	0.82	0.05	0.02	0.04
F-801B	1.2	tpy	0.4	tpy	0.81	0.05	0.02	0.04
F-801C	1.2	tpy	0.0	tpy	1.18	0.05	0.00	0.05
CRU								
F-101	1.2	tpy	0.6	tpy	0.56	0.05	0.03	0.03
F-102	1.2	tpy	0.6	tpy	0.54	0.05	0.03	0.02
DDU								
WB-301	3.4	tpy	3.5	tpy	-0.04	0.16	0.16	0.00
WB-302	2.7	tpy	4.8	tpy	-2.08	0.12	0.22	-0.10
ISOM								
H-1	7.4	tpy	12.9	tpy	-5.46	0.34	0.59	-0.25
HU								
B-501	15.5	tpy	52.3	tpy	-36.79	0.71	2.40	-1.69
FCU								
FCU 500	200.3	tpy	141.5	tpy	58.86	9.19	6.49	2.70
FCU 600	190.0	tpy	205.4	tpy	-15.44	8.72	9.43	-0.71

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

[2] 4UF Reformer Regen emissions based on data recorded by BP Whiting PI data collection system.

Table C.78. Existing Unit Lead Emissions

Process Unit	Operating Rate					Pb						
			Baseline Emissions			Future		Baseline		Calculation Cells		
	Future		(2001-2002)		Difference	EF	Unit	EF	Unit	Future	Baseline	tpy[1]
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	124.79	MMBtu/hr	49.1	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.7E-04	2.7E-04	1.1E-04
H-2	32.3	MMBtu/hr	27.59	MMBtu/hr	4.7	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	6.9E-05	5.9E-05	1.0E-05
H-3	49.2	MMBtu/hr	41.75	MMBtu/hr	7.5	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	1.1E-04	9.0E-05	1.6E-05
11C PS												
H-200	182.8	MMBtu/hr	157.60	MMBtu/hr	25.2	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.9E-04	3.4E-04	5.2E-05
H-300	72.0	MMBtu/hr	82.79	MMBtu/hr	-10.8	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	1.5E-04	1.8E-04	-2.3E-05
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	38.66	MMBtu/hr	-9.1	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	6.4E-05	8.3E-05	-1.9E-05
F-8A	142.3	MMBtu/hr	91.61	MMBtu/hr	50.7	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.1E-04	2.0E-04	1.1E-04
F-8B	142.3	MMBtu/hr	88.62	MMBtu/hr	53.7	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.1E-04	1.9E-04	1.2E-04
F-2	169.9	MMBtu/hr	206.97	MMBtu/hr	-37.1	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.6E-04	4.4E-04	-8.0E-05
F-3	180.0	MMBtu/hr	177.52	MMBtu/hr	2.5	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.9E-04	3.8E-04	5.3E-06
F-4	96.8	MMBtu/hr	112.22	MMBtu/hr	-15.4	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	2.1E-04	2.4E-04	-3.3E-05
F-5	48.8	MMBtu/hr	58.38	MMBtu/hr	-9.6	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	1.0E-04	1.3E-04	-2.1E-05
F-6	21.7	MMBtu/hr	28.71	MMBtu/hr	-7.0	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	4.7E-05	6.2E-05	-1.5E-05
F-7	36.2	MMBtu/hr	35.21	MMBtu/hr	1.0	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	7.8E-05	7.6E-05	2.1E-06
Regen												
ARU												
F-200A	144.4	MMBtu/hr	132.16	MMBtu/hr	12.2	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.1E-04	2.8E-04	2.6E-05
F-200B	144.4	MMBtu/hr	140.99	MMBtu/hr	3.4	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.1E-04	3.0E-04	7.3E-06
BOU												
F-401	23.0	MMBtu/hr	13.80	MMBtu/hr	9.2	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	4.9E-05	3.0E-05	2.0E-05
CFHU												
F-801A	24.6	MMBtu/hr	16.59	MMBtu/hr	8.0	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	5.3E-05	3.6E-05	1.7E-05
F-801B	24.6	MMBtu/hr	15.76	MMBtu/hr	8.8	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	5.3E-05	3.4E-05	1.9E-05
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.6	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	5.3E-05	0.0E+00	5.3E-05
CRU												
F-101	23.8	MMBtu/hr	28.80	MMBtu/hr	-5.0	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	5.1E-05	6.2E-05	-1.1E-05
F-102	23.8	MMBtu/hr	15.00	MMBtu/hr	8.8	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	5.1E-05	3.2E-05	1.9E-05
DDU												
WB-301	70.8	MMBtu/hr	26.35	MMBtu/hr	44.4	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	1.5E-04	5.7E-05	9.5E-05
WB-302	55.8	MMBtu/hr	60.54	MMBtu/hr	-4.7	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	1.2E-04	1.3E-04	-1.0E-05
ISOM												
H-1	153.2	MMBtu/hr	154.70	MMBtu/hr	-1.5	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.3E-04	3.3E-04	-3.2E-06
HU												
B-501	320.7	MMBtu/hr	167.81	MMBtu/hr	152.9	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	6.9E-04	3.6E-04	3.3E-04
FCU 500	103	1000 bbl/day	81.2	1000 bbl/day	21.8	0.000255	lb/1000 lb Coke Burn	0.000255	lb/1000 lb Coke Burn	8.53E-02	6.43E-02	2.10E-02
	669,191	1000 lb coke burned/yr	504,105	1000 lb coke burned/yr	165,086							
FCU 600	66	1000 bbl/day	57.1	1000 bbl/day	8.9	0.000255	lb/1000 lb Coke Burn	0.000255	lb/1000 lb Coke Burn	5.47E-02	4.10E-02	1.37E-02
	428,802	1000 lb coke burned/yr	321,581	1000 lb coke burned/yr	107,221							

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

Table C.79. Existing Unit Mercury Emissions

Process Unit	Operating Rate					Hg						
			Baseline Emissions			Future		Baseline		Calculation Cells		
	Future		(2001-2002)		Difference	EF	Unit	EF	Unit	Future	Baseline	tpy[1]
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	124.79	MMBtu/hr	49.1	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.4E-04	9.8E-05	3.9E-05
H-2	32.3	MMBtu/hr	27.59	MMBtu/hr	4.7	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	2.5E-05	2.2E-05	3.7E-06
H-3	49.2	MMBtu/hr	41.75	MMBtu/hr	7.5	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	3.9E-05	3.3E-05	5.9E-06
11C PS												
H-200	182.8	MMBtu/hr	157.60	MMBtu/hr	25.2	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.4E-04	1.2E-04	1.6E-05
H-300	72.0	MMBtu/hr	82.79	MMBtu/hr	-10.8	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	5.7E-05	6.5E-05	-8.5E-06
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	38.66	MMBtu/hr	-9.1	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	2.3E-05	3.0E-05	-7.1E-06
F-8A	142.3	MMBtu/hr	91.61	MMBtu/hr	50.7	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.1E-04	7.2E-05	4.0E-05
F-8B	142.3	MMBtu/hr	88.62	MMBtu/hr	53.7	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.1E-04	7.0E-05	4.2E-05
F-2	169.9	MMBtu/hr	206.97	MMBtu/hr	-37.1	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.3E-04	1.6E-04	-2.9E-05
F-3	180.0	MMBtu/hr	177.52	MMBtu/hr	2.5	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.4E-04	1.4E-04	2.0E-06
F-4	96.8	MMBtu/hr	112.22	MMBtu/hr	-15.4	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	7.6E-05	8.8E-05	-1.2E-05
F-5	48.8	MMBtu/hr	58.38	MMBtu/hr	-9.6	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	3.8E-05	4.6E-05	-7.6E-06
F-6	21.7	MMBtu/hr	28.71	MMBtu/hr	-7.0	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.7E-05	2.3E-05	-5.5E-06
F-7	36.2	MMBtu/hr	35.21	MMBtu/hr	1.0	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	2.9E-05	2.8E-05	7.8E-07
Regen												
ARU												
F-200A	144.4	MMBtu/hr	132.16	MMBtu/hr	12.2	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.1E-04	1.0E-04	9.7E-06
F-200B	144.4	MMBtu/hr	140.99	MMBtu/hr	3.4	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.1E-04	1.1E-04	2.7E-06
BOU												
F-401	23.0	MMBtu/hr	13.80	MMBtu/hr	9.2	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.8E-05	1.1E-05	7.3E-06
CFHU												
F-801A	24.6	MMBtu/hr	16.59	MMBtu/hr	8.0	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.9E-05	1.3E-05	6.3E-06
F-801B	24.6	MMBtu/hr	15.76	MMBtu/hr	8.8	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.9E-05	1.2E-05	7.0E-06
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.6	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.9E-05	0.0E+00	1.9E-05
CRU												
F-101	23.8	MMBtu/hr	28.80	MMBtu/hr	-5.0	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.9E-05	2.3E-05	-3.9E-06
F-102	23.8	MMBtu/hr	15.00	MMBtu/hr	8.8	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.9E-05	1.2E-05	6.9E-06
DDU												
WB-301	70.8	MMBtu/hr	26.35	MMBtu/hr	44.4	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	5.6E-05	2.1E-05	3.5E-05
WB-302	55.8	MMBtu/hr	60.54	MMBtu/hr	-4.7	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	4.4E-05	4.8E-05	-3.7E-06
ISOM												
H-1	153.2	MMBtu/hr	154.70	MMBtu/hr	-1.5	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.2E-04	1.2E-04	-1.2E-06
HU												
B-501	320.7	MMBtu/hr	167.81	MMBtu/hr	152.9	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	2.5E-04	1.3E-04	1.2E-04
FCU 500	103	1000 bbl/day	90.7	1000 bbl/day	12.3	1.00E-06	lb/1000 lb Coke Burn	1.00E-06	lb/1000 lb Coke Burn	3.35E-04	2.52E-04	8.25E-05
	669,191	1000 lb coke burned/yr	504,105	1000 lb coke burned/yr	165,086							
FCU 600	66	1000 bbl/day	55.7	1000 bbl/day	10.3	1.00E-06	lb/1000 lb Coke Burn	1.00E-06	lb/1000 lb Coke Burn	2.14E-04	1.61E-04	5.36E-05
	428,802	1000 lb coke burned/yr	321,581	1000 lb coke burned/yr	107,221							

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

Table C.80. Existing Unit Beryllium Emissions

Process Unit	Operating Rate					Be						
			Baseline Emissions			Future		Baseline		Calculation Cells		
	Future		(2001-2002)		Difference	EF	Unit	EF	Unit	Future	Baseline	tpy[1]
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	124.79	MMBtu/hr	49.1	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	9.0E-06	6.4E-06	2.5E-06
H-2	32.3	MMBtu/hr	27.59	MMBtu/hr	4.7	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.7E-06	1.4E-06	2.4E-07
H-3	49.2	MMBtu/hr	41.75	MMBtu/hr	7.5	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	2.5E-06	2.2E-06	3.8E-07
11C PS												
H-200	182.8	MMBtu/hr	157.60	MMBtu/hr	25.2	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.0E-05	8.1E-06	1.9E-06
H-300	72.0	MMBtu/hr	82.79	MMBtu/hr	-10.8	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	3.7E-06	4.3E-06	-5.6E-07
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	38.66	MMBtu/hr	-9.1	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.5E-06	2.0E-06	-4.7E-07
F-8A	142.3	MMBtu/hr	91.61	MMBtu/hr	50.7	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	7.3E-06	4.7E-06	2.6E-06
F-8B	142.3	MMBtu/hr	88.62	MMBtu/hr	53.7	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	7.3E-06	4.6E-06	2.8E-06
F-2	169.9	MMBtu/hr	206.97	MMBtu/hr	-37.1	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	8.8E-06	1.1E-05	-1.9E-06
F-3	180.0	MMBtu/hr	177.52	MMBtu/hr	2.5	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	9.3E-06	9.1E-06	1.3E-07
F-4	96.8	MMBtu/hr	112.22	MMBtu/hr	-15.4	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	5.0E-06	5.8E-06	-7.9E-07
F-5	48.8	MMBtu/hr	58.38	MMBtu/hr	-9.6	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	2.5E-06	3.0E-06	-4.9E-07
F-6	21.7	MMBtu/hr	28.71	MMBtu/hr	-7.0	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.1E-06	1.5E-06	-3.6E-07
F-7	36.2	MMBtu/hr	35.21	MMBtu/hr	1.0	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.9E-06	1.8E-06	5.1E-08
Regen												
ARU												
F-200A	144.4	MMBtu/hr	132.16	MMBtu/hr	12.2	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	7.4E-06	6.8E-06	6.3E-07
F-200B	144.4	MMBtu/hr	140.99	MMBtu/hr	3.4	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	7.4E-06	7.3E-06	1.8E-07
BOU												
F-401	23.0	MMBtu/hr	13.80	MMBtu/hr	9.2	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.2E-06	7.1E-07	4.7E-07
CFHU												
F-801A	24.6	MMBtu/hr	16.59	MMBtu/hr	8.0	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.3E-06	8.6E-07	4.1E-07
F-801B	24.6	MMBtu/hr	15.76	MMBtu/hr	8.8	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.3E-06	8.1E-07	4.6E-07
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.6	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.3E-06	0.0E+00	1.3E-06
CRU												
F-101	23.8	MMBtu/hr	28.80	MMBtu/hr	-5.0	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.2E-06	1.5E-06	-2.6E-07
F-102	23.8	MMBtu/hr	15.00	MMBtu/hr	8.8	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.2E-06	7.7E-07	4.5E-07
DDU												
WB-301	70.8	MMBtu/hr	26.35	MMBtu/hr	44.4	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	3.6E-06	1.4E-06	2.3E-06
WB-302	55.8	MMBtu/hr	60.54	MMBtu/hr	-4.7	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	2.9E-06	3.1E-06	-2.4E-07
ISOM												
H-1	153.2	MMBtu/hr	154.70	MMBtu/hr	-1.5	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	7.9E-06	8.0E-06	-7.7E-08
HU												
B-501	320.7	MMBtu/hr	167.81	MMBtu/hr	152.9	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.7E-05	8.6E-06	7.9E-06
FCU 500	103	1000 bbl/day	90.7	1000 bbl/day	12.3	3.51E-06	lb/1000 lb Coke Burn	3.51E-06	lb/1000 lb Coke Burn	1.17E-03	8.85E-04	2.90E-04
	669,191	1000 lb coke burned/yr	504,105	1000 lb coke burned/yr	165,086							
FCU 600	66	1000 bbl/day	55.7	1000 bbl/day	10.3	3.51E-06	lb/1000 lb Coke Burn	3.51E-06	lb/1000 lb Coke Burn	7.53E-04	5.64E-04	1.88E-04
	428,802	1000 lb coke burned/yr	321,581	1000 lb coke burned/yr	107,221							

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

Table C.81. Summary of Emissions from New Emission Units

Process Unit	VOC (ton/yr)	NO_x (ton/yr)	SO_2 (ton/yr)	PM (Filterable) (ton/yr)	PM_{10} (Filterable + Condensable) (ton/yr)	CO (ton/yr)	Sulfuric Acid Mist (ton/yr)	Lead (ton/yr)	Mercury (ton/yr)	Beryllium (ton/yr)	H_2S (tons/yr)	Total Reduced Sulfur (ton/yr)
Heaters												
DHT[1]												
B-601A - Duty - 42 MMBtu/hr	1.0	7.3	0.1	0.3	1.4	7.3	0.00	9.0E-05	3.3E-05	2.2E-06		
GOHT[2]												
F-901A - Duty 47 - MMBtu/hr	1.1	8.2	2.3	0.4	1.5	4.1	0.10	1.0E-04	3.7E-05	2.4E-06		
F-901B - Duty 47 - MMBtu/hr	1.1	8.2	2.3	0.4	1.5	4.1	0.10	1.0E-04	3.7E-05	2.4E-06		
12 PS[3]												
H-101A - Duty 355 MMBtu/hr	8.4	77.7	17.2	2.9	11.6	29.5	0.79	7.6E-04	2.8E-04	1.8E-05		
H-102 - Duty 331 MMBtu/hr	7.8	72.5	16.0	2.7	10.8	27.5	0.74	7.1E-04	2.6E-04	1.7E-05		
H-101B - Duty 355 MMBtu/hr	8.4	77.7	17.2	2.9	11.6	29.5	0.79	7.6E-04	2.8E-04	1.8E-05		
Coker[4] (#2 Coker)												
Heater H-201 - Duty 208 MMBtu/hr	4.9	18.2	10.1	2.3	7.4	17.3	0.46	4.5E-04	1.6E-04	1.1E-05		
Heater H-202 - Duty 208 MMBtu/hr	4.9	18.2	10.1	2.3	7.4	17.3	0.46	4.5E-04	1.6E-04	1.1E-05		
Heater H-203 - Duty 208 MMBtu/hr	4.9	18.2	10.1	2.3	7.4	17.3	0.46	4.5E-04	1.6E-04	1.1E-05		
Cooling Towers[5]												
New Cooling Tower 7	3.9			0.5	0.5							
New Cooling Tower 8	17.1			2.2	2.2							
New HU Cooling Tower	-			1.8	1.8							
SRU[6]												
New Claus Train D												
New Claus Train E												
Claus Offgas Treaters 1 and 2*	3.4	50.5	194.8	1.2	4.7	55.0	8.94	3.1E-04	1.1E-04	7.4E-06	14.3	14.3
Flares[7]												
GOHT Flare												
Pilot Emissions	0.0	0.2	0.00	0.00	0.01	0.2	0.00	9.2E-07	3.4E-07	2.2E-08		
Purge Emissions	2.1	1.0	0.2	0.0	0.1	5.5	0.01	7.3E-06	2.7E-06	2.7E-06		
South Flare												
Pilot Emissions	0.01	0.2	0.00	0.00	0.01	0.2	0.00	9.2E-07	3.4E-07	2.2E-08		
Purge Emissions	2.4	1.2	0.2	0.0	0.1	6.4	0.01	8.5E-06	8.5E-06	8.5E-06		
HU Flare												
Pilot Emissions	0.01	0.1	0.00	0.00	0.01	0.1	0.00	5.6E-07	2.1E-07	1.3E-08		
Fugitives from new and modified units												
DHT	0.6											
GOHT	23.7											
12 PS	5.8											
Coker	25.6											
SRU	4.2											
OSBL	0.9											
ARU	0.3											
BOU	0.0											
ISOM	0.2											
DDU	0.3											
OCC Sewer Changes	31.5											
Emissions Associated with Third Parties												
Hydrogen Plant[8] (3rd Party SMR)												
HU-1 - Duty 920 MMBtu/hr	13.7	52.4	0.6	27.4	27.4	60.4	0.0	4.9E-04	1.8E-04	1.2E-05		
HU-2 - Duty 920 MMBtu/hr	13.7	52.4	0.6	27.4	27.4	60.4	0.0	4.9E-04	1.8E-04	1.2E-05		
HU Fugitive Emissions	6.8					25.0						
New Storage Tanks[9]												
TK-6255 - Coker Feed Tank	0.06											
TK-SH-1and TK-SH-2 - Sulfur Bulk Storage Tanks Vented to Caustic Scrubber[10]											0.5	0.5
TK-5052 - Stormwater/Equalization Tank	0.01											
Brine Treatment System Tanks												
(TK-105A) Off spec tank 1[11]	0.72											
(TK-105B) Off spec tank 2[11]	0.72											
(TK-101) Separation tank 1[11]	0.43											
(TK-102) Separation tank 2[11]	0.43											
(TK-103) Separation tank 3[11]	0.43											
(TK-104A) Sludge holding tank 1[11]	0.44											
(TK-104B) Sludge holding tank 2[11]	0.44											
Fugitives dust from new coke handling				1.4	0.7				1.42E-06			
Particulate Emissions from Concrete Crushing				0.1	0.0							
Potential Emissions Increase from New Units	**202.47**	**464.35**	**281.67**	**78.77**	**125.80**	**367.36**	**12.93**	**5.18E-03**	**1.91E-03**	**1.35E-04**	**14.8**	**14.8**

[1] New DHT heater B-601A controlled by ultra-low NOx burners. Note this heater is replacing the existing DHT heater.
[2] New GOHT heaters F-901A and F-901B controlled by ultra-low NOx burners.
[3] 12PS H-2, H-1B, H-1AS, H-1AN, H-1CX and H-1CN are not being replaced with like-for-like replacement heaters. Therefore, the new heaters are considered new
[4] New Coker (#2 Coker) heaters H-201, H-202, and H-203 are controlled by low NOx burners and SCRs.
[5] New Cooling Towers based on 0.001% Liquid Drift Factor achieved with high efficiency drift eliminators.
[6] The two new SRU Claus trains have no direct emissions and are vented through new Claus Offgas Treaters (COTs).
[7] Flare emissions based on normal operation (i.e., purge gas flow rate).
[8] Hydrogen plant (3rd Party SMR) heaters HU-1 and HU-2 are controlled by low NOx burners and SCRs.
Additional CO fugitive emissions are included to account for general process fugitive emissions.
[9] All tanks emissions except for Tanks SH-1 and SH-2 were calculated using U.S. EPA's TANKS 4.0 Program.
[10] Total reduced sulfur (TRS) emissions from Tanks SH-1 and SH-2 were estimated based on anticipated TRS concentration after caustic scrubber.
[11] Tanks are controlled to 95% reduction in VOC emissions.
* Note SO_2 emissions from the COT 1 and COT 2 include future sulfur loading emissions.

Table C.82. Project Net Emission Increases

Project Emissions Baseline 24-Month Period[1]	2001-2002	1999-2000	2001-2002	2001-2002	1999-2000	2003-2004	2001-2002	2001-2002	2001-2002	2000-2001	2000-2001
Pollutant	**VOC (ton/yr)**	**NOx (ton/yr)**	**PM (Filterable) (ton/yr)**	**$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[12] (ton/yr)**	**CO (ton/yr)**	**Sulfuric Acid Mist (ton/yr)**	**Pb (ton/yr)**	**Hg (ton/yr)**	**Be (ton/yr)**	**H_2S (ton/yr)**	**Total Reduced Sulfur (ton/yr)**
Project Emission Increase (PEI) New Units[2]	202.5	464.4	78.8	125.8	367.4	12.93	5.18E-03	0.002	0.000135	14.8	14.8
PEI Affected Units[3]	23.1	20.6	60.1	90.9	174.5	(0.18)	3.55E-02	0.0004	0.000497	-	-
PEI	**225.6**	**485.0**	**138.9**	**216.7**	**541.8**	**12.7**	**4.07E-02**	**0.002**	**0.00063**	**14.8**	**14.8**
PSD Significant Emission Rate (SER)	**40.0**	**40.0**	**25.0**	**15.0**	**100.0**	**7.0**	**6.00E-01**	**0.1**	**0.0004**	**10.0**	**10.0**
Significant Project Emission Increase?	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes
Past Contemporaneous Changes											
NOx SIP Call - 3SPS (Permit No. 089-16586-0000) Effective Date: 1/30/2003	-	-	-	-	-	-					
FBI HWC MACT Project (Permit No. 089-16960-00453) Effective Date: 5/27/2003	-	-	-	-	-	-					
Consent Decree - No oil burning & FCU CO limits (Permit No. 089-15202-00003) Effective Date: 6/1/2003	-	-	(161.8)	(161.8)	-	(123.6)	(0.05880)	(0.00110)	(0.00571)		
DDU Debottlenecking Project (Permit No. 089-17230-00453) Effective Date: 9/10/2003	1.1	24.2	0.8	0.8	8.1	0.0					
CRU Conversion Project (Permit No. 089-15052-00453) Effective Date: 7/11/2003	2.2	23.9	1.6	1.6	33.9	0.7					
Sufur Pit Control Effective Date: 10/2003										(20.1)	(20.1)
ULSD Project (Permit No. 089-19754-00453) Effective date: 11/17/2003	8.4	2.0	0.1	0.1	1.6	0.0					
MACT II Project (Permit No. 089-19041-00453) Effective date: 7/15/2004	-	-	-	-	-	-					
Tank 3900 Modifications (Permit No. 089-21591-00453) Effective Date: 10/12/2005	0.8	-	-	-	-	-					
Steam to US Steel (Permit No. 089-21879-00003) Effective date: 11/18/2005	-	-	-	-	-	-					
Oxidizers on Remediation (Permit No. 089-21682-00453) Effective date: 12/20/2005	0.7	0.6	0.0	0.0	0.5	0.0					
Shutdown of Tank 3703[4] Effective date: 2/28/2006	(7.4)	-	-	-	-	-					
Sour Water Tank (TK 410) (Permit No. 089-23341-00453) Effective date: 8/25/06	2.8					-					
Asphalt Infrastructure Project (Increases) (Permit No. 089-24068-00453) Effective date: 2/20/07	1.9	6.4	1.0	1.0	10.8	0.0					
Asphalt Infrastructure Project (Decreases)[4] Submitted: 10/13/06	(3.8)					-					
Tank Cleaning Project (Permit No. 089-24258-00453) Effective date: 3/30/2007	6.8	24.7	1.8	2.0	5.4	0.1					
Net Emissions Increase (NEI) with Past Contemporaneous Changes	**239.0**	**566.8**	**(17.5)**	**60.5**	**602.2**	**(110.0)**	**-1.81E-02**	**1.23E-03**	**-5.08E-03**	**(5.3)**	**(5.3)**
Creditable Emission Reductions											
Coker[5] - Shutdown Heaters	(3.7)	(81.0)	(1.3)	(2.7)	(68.0)	(0.6)	-3.33E-04	-1.22E-04	-8.00E-06	-	-
NEI - Coker Shutdown Heaters	**235.3**	**485.9**	**(18.7)**	**57.8**	**534.2**	**(110.6)**	**-1.85E-02**	**1.10E-03**	**-5.08E-03**	**(5.3)**	**(5.3)**
Coker[5] - Shutdown Fugitives	(21.3)									-	-
NEI - Coker Shutdown Fugitives	**214.0**	**485.9**	**(18.7)**	**57.8**	**534.2**	**(110.6)**	**-1.85E-02**	**1.10E-03**	**-5.08E-03**	**(5.3)**	**(5.3)**
Beavon-Stretford TGU[5] - Shutdown	(0.2)	(3.4)	(0.1)	(0.3)	(2.9)	(0.0)	-1.64E-05	-6.04E-06	-3.95E-07	(2.3)	(62.5)
NEI - Beavon-Stretford TGU Shutdown	**213.9**	**482.4**	**(18.8)**	**57.5**	**531.3**	**(110.6)**	**-1.85E-02**	**1.10E-03**	**-5.08E-03**	**(7.6)**	**(67.8)**
SBS TGU[5] - Shutdown	(0.1)	-	(0.0)	(0.1)	-	(0.2)	-9.86E-06	-3.62E-06	-2.37E-07	-	-
NEI - SBS TGU - Shutdown	**213.7**	**482.4**	**(18.8)**	**57.4**	**531.3**	**(110.8)**	**-1.85E-02**	**1.10E-03**	**-5.08E-03**	**(7.6)**	**(67.8)**
SBS Cooling Tower[5] - Shutdown	(0.4)	-	(0.8)	(0.8)		-				-	-
NEI - SBS Cooling Tower - Shutdown	**213.4**	**482.4**	**(19.7)**	**56.6**	**531.3**	**(110.8)**	**-1.85E-02**	**1.10E-03**	**-5.08E-03**	**(7.6)**	**(67.8)**
SRU Incinerator[5] - Shutdown	(0.3)	(5.6)	(0.1)	(0.4)	(5.0)	(0.0)	-2.66E-05	-9.78E-06	-6.39E-07	-	-
NEI - SRU Incinerator - Shutdown	**213.1**	**476.9**	**(19.8)**	**56.2**	**526.3**	**(110.8)**	**-1.85E-02**	**1.09E-03**	**-5.08E-03**	**(7.6)**	**(67.8)**
12PS[5] - Shutdown Heater H-2	(2.6)	(15.0)	(0.9)	(3.7)	(0.0)	(0.5)	-2.40E-04	-8.82E-05	-5.76E-06	-	-
NEI - Shutdown 12 PS Heater H-2	**210.4**	**461.9**	**(20.7)**	**52.5**	**526.3**	**(111.3)**	**-1.87E-02**	**9.97E-04**	**-5.09E-03**	**(7.6)**	**(67.8)**
12PS[5] - Shutdown Heaters H-1AS/AN	(2.8)	(117.9)	(1.0)	(3.9)	(35.4)	(0.6)	-2.55E-04	-9.38E-05	-6.13E-06	-	-
NEI - Shutdown 12 PS Heaters H-1AS/AN	**207.6**	**343.9**	**(21.6)**	**48.6**	**490.9**	**(111.9)**	**-1.90E-02**	**9.03E-04**	**-5.10E-03**	**(7.6)**	**(67.8)**
12PS[5] - Shutdown Heater H-1CN	(1.0)	(14.8)	(0.4)	(0.8)	(12.4)	(0.3)	-9.34E-05	-3.43E-05	-2.24E-06	-	-
NEI - Shutdown 12 PS Heater H-1CN	**206.6**	**329.2**	**(22.0)**	**47.9**	**478.5**	**(112.2)**	**-1.91E-02**	**8.69E-04**	**-5.10E-03**	**(7.6)**	**(67.8)**
12PS[5] - Shutdown Heater H-1B	(3.9)	(202.7)	(1.3)	(5.4)	(60.8)	(0.7)	-3.54E-04	-1.30E-04	-8.50E-06	-	-
NEI - Shutdown 12 PS Heater H-1B	**202.7**	**126.5**	**(23.3)**	**42.5**	**417.7**	**(112.9)**	**-1.94E-02**	**7.39E-04**	**-5.11E-03**	**(7.6)**	**(67.8)**
12PS[5] - Shutdown Heater H-1CX	(5.1)	(79.4)	(1.8)	(3.5)	(66.1)	(1.0)	-4.66E-04	-1.71E-04	-1.12E-05	-	-
NEI - Shutdown 12 PS Heater H-1CX	**197.6**	**47.0**	**(25.1)**	**39.0**	**351.6**	**(113.9)**	**-1.99E-02**	**5.68E-04**	**-5.12E-03**	**(7.6)**	**(67.8)**
Fugitive Dust from Coke Storage, Handling, and Transport[5] - Shutdown	-		(179.1)	(43.9)				-6.19E-05	0.00E+00	-	-
NEI - Fugitive Dust from Coker Process	**197.6**	**47.0**	**(204.2)**	**(5.0)**	**351.6**	**(113.9)**	**-1.99E-02**	**5.06E-04**	**-5.12E-03**	**(7.6)**	**(67.8)**
No. 4 Treatment Plant[5] - Shutdown Fugitive Components	(0.2)									-	-
NEI - Shutdown Fugitive Components	**197.3**	**47.0**	**(204.2)**	**(5.0)**	**351.6**	**(113.9)**	**-1.99E-02**	**5.06E-04**	**-5.12E-03**	**(7.6)**	**(67.8)**
VRU 300[5] - Shutdown Fugitive Components	(6.2)										
NEI - Shutdown Fugitive Components	**191.2**	**47.0**	**(204.2)**	**(5.0)**	**351.6**	**(113.9)**	**-1.99E-02**	**5.06E-04**	**-5.12E-03**	**(7.6)**	**(67.8)**
LDAR - Control Existing Heavy Liquid Pumps	(27.3)	-	-	-	-					-	-
NEI - Control Existing HL Pumps	**163.9**	**47.0**	**(204.2)**	**(5.0)**	**351.6**	**(113.9)**	**-1.99E-02**	**5.06E-04**	**-5.12E-03**	**(7.6)**	**(67.8)**
Sulfur Loading Reduction										(8.4)	(8.4)
NEI - Sulfur Loading Reductions	**163.9**	**47.0**	**(204.2)**	**(5.0)**	**351.6**	**(113.9)**	**-1.99E-02**	**5.06E-04**	**-5.12E-03**	**(15.9)**	**(76.1)**
NEI with Creditable Emission Reductions	**163.9**	**47.0**	**(204.2)**	**(5.0)**	**351.6**	**(113.9)**	**-1.99E-02**	**5.06E-04**	**-5.12E-03**	**(15.9)**	**(76.1)**

Table C.82. Project Net Emission Increases

Project Emissions Baseline 24-Month Period[1]	2001-2002	1999-2000	2001-2002	2001-2002	1999-2000	2003-2004	2001-2002	2001-2002	2001-2002	2000-2001	2000-2001
Pollutant	**VOC (ton/yr)**	**NOx (ton/yr)**	**PM (Filterable) (ton/yr)**	**$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[12] (ton/yr)**	**CO (ton/yr)**	**Sulfuric Acid Mist (ton/yr)**	**Pb (ton/yr)**	**Hg (ton/yr)**	**Be (ton/yr)**	**H_2S (ton/yr)**	**Total Reduced Sulfur (ton/yr)**
Future Non-CXHO Contemporaneous Projects											
No. 1 Stanolind Power Station[6,10] - Shutdown	(8.6)		(2.8)	(11.2)	(268.0)	(1.5)	-7.34E-04	-2.69E-04	-1.76E-05		
NEI - 1SPS Shutdown	**155.3**	**47.0**	**(207.0)**	**(16.1)**	**83.6**	**(115.4)**	**-2.06E-02**	**2.37E-04**	**-5.14E-03**	**(15.94)**	**(76.14)**
3UF[6] - Shutdown Heaters H-1	(3.7)	(189.6)	(1.3)	(2.8)	(56.9)	(0.2)	-3.39E-04	-1.24E-04	-8.13E-06		
NEI - 3UF Heater H-1 Shutdown	**151.5**	**(142.6)**	**(208.3)**	**(18.9)**	**26.7**	**(115.6)**	**-2.10E-02**	**1.12E-04**	**-5.14E-03**	**(15.94)**	**(76.14)**
3UF[6] - Shutdown Heaters H-2 and F-7	(3.9)	(181.4)	(1.3)	(2.9)	(58.9)	(0.2)	-3.50E-04	-1.29E-04	-8.41E-06		
NEI - 3UF Heater H-2 and F-7 Shutdown	**147.7**	**(324.0)**	**(209.6)**	**(21.8)**	**(32.1)**	**(115.8)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
3UF[6,7] - Shutdown Reformer Section	(1.2)				(8.0)	(0.1)					
NEI - 3UF Reformer Section Shutdown	**146.5**	**(324.0)**	**(209.6)**	**(21.8)**	**(40.1)**	**(115.9)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
3UF[6] - Shutdown Fugitive Components	(10.8)										
NEI - 3UF Fugitive Components Shutdown	**135.7**	**(324.0)**	**(209.6)**	**(21.8)**	**(40.1)**	**(115.9)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
Marine Dock[8] - Install VRU or VCU	(175.4)	5.6			2.2						
NEI - Marine Dock VRU	**(39.8)**	**(318.4)**	**(209.6)**	**(21.8)**	**(37.9)**	**(115.9)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
Cooling Towers[9] - Install Drift Eliminator on Cooling Tower 2			(15.6)	(15.6)							
NEI - Cooling Tower 2 Drift Eliminator	**(39.8)**	**(318.4)**	**(225.1)**	**(37.3)**	**(37.9)**	**(115.9)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
Cooling Towers[9] - Install Drift Eliminators on Cooling Tower 3			(40.4)	(40.4)							
NEI - Cooling Tower 3 Drift Eliminator	**(39.8)**	**(318.4)**	**(265.5)**	**(77.7)**	**(37.9)**	**(115.9)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
Cooling Towers[9] - Install Drift Eliminators on Cooling Tower 4			(24.1)	(24.1)							
NEI - Cooling Tower 4 Drift Eliminator	**(39.8)**	**(318.4)**	**(289.6)**	**(101.7)**	**(37.9)**	**(115.9)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
Lakefront Fluidized Bed Incinerator[6] - Shutdown	(7.3)	(16.8)	(3.9)	(3.9)	(2.1)	(0.1)	-2.46E-03	-2.27E-03	-6.35E-05		
NEI - Shutdown FBI	**(47.0)**	**(335.2)**	**(293.5)**	**(105.7)**	**(40.0)**	**(116.1)**	**-2.38E-02**	**-2.28E-03**	**-5.22E-03**	**(15.94)**	**(76.14)**
Tank BT-002 Modification	0.6										
NEI - Tank BT-002 Modification	**(46.4)**	**(335.2)**	**(293.5)**	**(105.7)**	**(40.0)**	**(116.1)**	**-2.38E-02**	**-2.28E-03**	**-5.22E-03**	**(15.94)**	**(76.14)**
Boiler Project	27.2	322.0	9.2	40.0	118.9	2.3	2.43E-03	8.92E-04	5.83E-05		
NEI - Boiler Project	**(19.2)**	**(13.2)**	**(284.3)**	**(65.7)**	**78.9**	**(113.8)**	**-2.14E-02**	**-1.39E-03**	**-5.16E-03**	**(15.94)**	**(76.14)**
3 SPS SCR Project	5.6	2.2	1.6	22.9	(106.7)	0.9	4.25E-04	1.56E-04	1.02E-05		
NEI - 3SPS SCR	**(13.7)**	**(11.0)**	**(282.7)**	**(42.8)**	**(27.8)**	**(112.9)**	**-2.09E-02**	**-1.23E-03**	**-5.15E-03**	**(15.94)**	**(76.14)**
Fire Pump Engines	0.7	5.0	0.3	0.3	1.7	0.0					
NEI - Fire Pump Engines	**(12.9)**	**(6.0)**	**(282.4)**	**(42.5)**	**(26.2)**	**(112.9)**	**-2.09E-02**	**-1.23E-03**	**-5.15E-03**	**(15.94)**	**(76.14)**
Thermal Desorption	2.4	5.2	0.5	0.8	1.3	0.1	3.15E-04	1.05E-04	1.05E-04		
NEI - Thermal Desorption System	**(10.5)**	**(0.8)**	**(281.9)**	**(41.7)**	**(24.9)**	**(112.8)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
Tank 8 Replacement	6.1										
NEI - Tank 8 Replacement	**(4.4)**	**(0.8)**	**(281.9)**	**(41.7)**	**(24.9)**	**(112.8)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
Tank 3637	0.2										
NEI - Tank 3637	**(4.2)**	**(0.8)**	**(281.9)**	**(41.7)**	**(24.9)**	**(112.8)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
11A PS WARP	2.2	0.1	0.0	0.0	0.4	0.0	5.49E-07	2.01E-07	1.32E-08		
NEI - 11A PS WARP	**(2.0)**	**(0.8)**	**(281.9)**	**(41.7)**	**(24.5)**	**(112.8)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
11C PS WARP	(3.9)	0.1	0.0	0.0	0.5	0.1	6.01E-07	2.21E-07	1.44E-08		
NEI - 11C PS WARP	**(5.9)**	**(0.7)**	**(281.9)**	**(41.6)**	**(24.0)**	**(112.7)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
FCU500 WARP[11]	1.0	0.0	0.0	0.0	0.1	0.0	1.79E-07	6.56E-08	4.29E-09		
NEI - FCU500 WARP	**(4.9)**	**(0.7)**	**(281.9)**	**(41.6)**	**(23.9)**	**(112.7)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
FCU600 WARP	(1.5)	0.0	0.0	0.0	0.1	0.0	1.79E-07	6.56E-08	4.29E-09		
NEI - FCU600 WARP	**(6.4)**	**(0.6)**	**(281.9)**	**(41.6)**	**(23.7)**	**(112.7)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
FCU600 TAR	0.3										
NEI - FCU600 TAR	**(6.1)**	**(0.6)**	**(281.9)**	**(41.6)**	**(23.7)**	**(112.7)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
VRU100/200 WARP	(0.2)	0.0	0.0	0.0	0.0	0.0	3.15E-08	1.16E-08	7.55E-10		
NEI - VRU100/200 WARP	**(6.3)**	**(0.6)**	**(281.9)**	**(41.6)**	**(23.7)**	**(112.7)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
NEI with Non-CXHO Contemporaneous Projects	**(6.3)**	**(0.6)**	**(281.9)**	**(41.6)**	**(23.7)**	**(112.7)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.9)**	**(76.1)**

NEI Project Emissions	**-6.3**	**-0.6**	**-281.9**	**-41.6**	**-23.7**	**-112.7**	**-0.021**	**-0.00113**	**-0.00504**	**-15.9**	**-76.1**
PSD SERs (tpy)	**40.0**	**40.0**	**25.0**	**15.0**	**100.0**	**7.0**	**0.6**	**0.1**	**0.0004**	**10**	**10**
Significant Net Emissions Increase?	No	No	No	No	No	No	No	No	No	No	No
Pollutant	**VOC (ton/yr)**	**NOx (ton/yr)**	**PM (Filterable) (ton/yr)**	**$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[13] (ton/yr)**	**CO (ton/yr)**	**Sulfuric Acid Mist (ton/yr)**	**Pb (ton/yr)**	**Hg (ton/yr)**	**Be (ton/yr)**	**H_2S (ton/yr)**	**Total Reduced Sulfur (ton/yr)**

[1] Selected 24-month period is based on calendar years.
[2] PEI New Units from Table C.81.
[3] PEI Affected Units from "Evaluation of Project Impacts on Existing Units" (Tables C.71 through C.80)
[4] Emissions decreases for past contemporaneous projects are being made enforceable as part of the CXHO Project. The emissions decreases were documented in the respective permit applications.
[5] Unit shutdown values based on average past actual emissions for baseline period.
[6] Unit shutdown values for future non-CXHO contemporaneous projects are based on a 24-month period average past actual emissions.
[7] 3UF Reformer emissions based on data recorded by BP Whiting PI data collection system.
[8] Marine Dock VOC emissions based on 2003-2004 total average emissions controlled to 10 mg of VOC/L of throughput for gasoline loading.
[9] Existing Cooling Towers 2, 3, and 4 will be controlled to 0.001% liquid drift. Note half of the Cooling Tower 2 modules are already controlled to 0.001% liquid drift. Contemporaneous to the CXHO Project the other modules will be controlled with high efficiency drift eliminators.
[10] No creditable NO_X decrease was taken for the shutdown of the 1SPS boilers per the consent decree.
[11] The FCU 500 WARP emergency/malfunction flaring emissions are assumed to be equivalent to the FCU 600 WARP emissions. The projects will be similar; however, the FCU 500 WARP release rates have not yet been estimated si project design is not yet complete.
[12] Based on interim guidance from US EPA, $PM_{2.5}$ is evaluated based on significant emission rate thresholds established for PM_{10}. The current PM_{10} SIP limits filterable PM_{10} emissions and compliance is based on reference test method filterable particulate matter). Although not required, BP Whiting has conservatively adjusted the PM_{10} baseline based on the PM_{10} SIP limits for PSD applicability purposes, which includes both filterable and condensable PM_{10}. $PM_{2.5}$ er by the Lake County PM_{10} SIP, however, to be conservative, BP Whiting has adjusted $PM_{2.5}$ baseline emissions in the same manner as for PM_{10} emissions.

Table C.82a. Sulfur Dioxide Project Net Emission Increases per Consent Decree[1] Requirements

Project Emissions Baseline 24-Month Period[2]	2003-2004
Pollutant	**SO_2 (ton/yr)**
Project Emission Increase (PEI) New Units[3]	281.7
PEI Affected Units[4]	(4.0)
PEI	**277.7**
PSD Significant Emission Rate (SER)	**40.0**
Significant Project Emission Increase?	Yes

Sulfur Dioxide Netting Analysis

Increases from "Lower Sulfur Fuels Units"	
Affected Unit Project Increases	
BOU - Heater F-401	0.8
CFHU - Heaters F-801A, F-801B, F-801C	2.8
CRU - Heaters F-101 and F-102	1.1
4UF - Heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, and F-8B	21.8
FCU 500	58.9
New Unit Project Increases	
DHT - Heater B-601A	0.1
GOHT - Heaters F-901A and F-901B	4.6
Hydrogen Plant (3rd Party SMR) - Heaters HU-1 and HU-2	1.2
Past Contemporaneous Changes	
DDU Debottlenecking Project (Permit No. 089-17230-00453) Effective Date: 9/10/2003	0.1
CRU Conversion Project (Permit No. 089-15052-00453) Effective Date: 7/11/2003	15.9
ULSD Project (Permit No. 089-19754-00453) Effective date: 11/17/2003 Project Emissions excluding heater emissions.	0.1
Consent Decree[1] Decreases that Offset Increases at "Lower Sulfur Fuels Units"	
Consent Decree - No oil burning & FCU CO limits (Permit No. 089-15202-00003) Effective Date: 6/1/2003	(269.4)
Total Increases from "Lower Sulfur Fuels Units"	107.3
Total Consent Decree[1] Decreases that Offset Increases at "Lower Sulfur Fuels Units"	(269.4)
Net Emissions for "Lower Sulfur Fuels Units"[5]	-

Increases from Other "Netting/Offset Generating Units"	
New Unit Project Increases	
12 PS Heaters - H-101A, H-101B, and H-102	50.4
#2 Coker - Heaters H-201, H-202, and H-203	30.2
Future Non-CXHO Contemporaneous Projects	
Boiler Project	49.8
3 SPS SCR Project	19.0
Consent Decree[1] Decreases that Offset Other "Netting/Offset Generating Units"	
Consent Decree - Reduce FCU 600 SO_2 limit to 50 ppm	(160.9)
Total Increases from Other "Netting/Offset Generating Units"	149.5
Total Consent Decree[1] Decreases that Offset Other "Netting/Offset Generating Units"	(160.9)
Net Emissions for Other "Netting/Offset Generating Units"[6]	-

Increases from Remaining Units	
New Unit Project Increases	
SRU	
New Claus Train D	
New Claus Train E	
Claus Offgas Treaters 1 and 2	194.8
Flares	
GOHT Flare	
Pilot Emissions	0.0
Purge Emissions	0.2
South Flare	
Pilot Emissions	0.0
Purge Emissions	0.2
HU Flare	
Pilot Emissions	0.0
Past Contemporaneous Changes	
Oxidizers on Remediation (Permit No. 089-21682-00453) Effective date: 12/20/2005	0.2
Asphalt Infrastructure Project (Increases) (Permit No. 089-24068-00453) Effective date: 2/20/07	0.1
Tank Cleaning Project (Permit No. 089-24258-00453) Effective date: 3/30/2007	2.9
Future Non-CXHO Contemporaneous Projects	
Fire Pump Engines	0.1
Thermal Desorption	1.8
11A PS WARP	0.3
11C PS WARP	2.6
FCU500 WARP	0.0
FCU600 WARP	0.0
VRU100/200 WARP	0.0
Decreases that Offset Increases at Remaining Units	
Affected Unit Project Increases	
11A PS - Heater H-1X, H-2, and H-3	(7.5)
11C PS - Heaters H-200 and H-300	(4.2)
ARU - Heaters F-200A and F-200B	(17.8)
DDU - Heaters WB-301 and WB-302	(2.1)
ISOM - Heater H-1	(5.5)
HU - Heater B-501	(36.8)
FCU 600 - Reduce SO_2 to 37 ppm outlet concentration	(15.4)
Creditable Emissions Reductions	
Coker - Shutdown Heaters	(12.7)
Beavon-Stretford TGU - Shutdown	(8.7)
SBS TGU - Shutdown	(3.5)
SRU Incinerator - Shutdown	(0.0)
12PS - Shutdown Heater H-2	(11.9)
12PS - Shutdown Heaters H-1AS/AN	(13.6)
12PS - Shutdown Heater H-1CN	(5.5)
12PS - Shutdown Heater H-1B	(16.1)
12PS - Shutdown Heater H-1CX	(21.5)
Future Non-CXHO Contemporaneous Projects	
No. 1 Stanolind Power Station - Shutdown	(32.8)
3UF - Shutdown Heaters H-1	(4.6)
3UF - Shutdown Heaters H-2 and F-7	(4.6)
3UF - Shutdown Reformer Section	(2.5)
Lakefront Fluidized Bed Incinerator - Shutdown	(2.8)
Total Increases from Remaining Units	203.3
Total Decreases that Offset Increases at Remaining Units	(230.1)
Net SO_2 Emissions for CXHO Projects	(26.7)

Net Emissions for "Lower Sulfur Fuels Units"	-
Net Emissions for Other "Netting/Offset Generating Units"	-
Net Emissions for Remaining Units	(26.7)
SO_2 NEI Project Emissions	**(26.7)**
PSD SERs (tpy)	**40.0**
Significant Net Emissions Increase?	No

1. United States, et. al. v. BP Exploration & Oil, et. Al.; Northern District of Indiana, Hammond Division; Civil Action No. 2:96 CV 095 RL.
2. Selected 24-month period is based on calendar years.
3. PEI New Units from Table C.81.
4. PEI Affected Units from "Evaluation of Project Impacts on Existing Units" (Tables C.71 through C.80)
5. The Consent Decree specifies that no more than ten percent (10%) of the SO_2 emission reduction credits generated by the cessation of oil burning could be used for netting SO_2 emissions increases that result from the construction or modification of "lower sulfur fuels units" that meet the criteria for "netting/offset generating units". Therefore, any reduction beyond the emissions increases from "lower sulfur fuels units" cannot be used to offset other increases and are not carried forward in this netting analysis
6. The Consent Decree specifies that no more than ten percent (10%) of the SO_2 emission reduction credits generated by the FCU 600 SO_2 emissions reduction to 50 ppm could be used for netting SO_2 emissions increases that result from the construction or modification of "netting/offset generating units". Therefore, any reduction beyond the emissions increases from "netting/offset generating units" cannot be used to offset other increases and are not carried forward in this netting analysis.

Table C.83. Project VOC de minimis Test

Per 326 IAC 2-3-1(q), a de minimis increase of VOC from a modification in a serious or severe ozone nonattainment area, means an increase that does not exceed twenty-five (25) tons per year when the net emissions increases from the proposed modification are aggregated on a pollutant specific basis with all other net emissions increases from the source over a five (5) consecutive calendar year period prior to, and including, the year of the modification. This modification is expected to commence operation in 2011, and therefore the net emissions changes from projects taking place between 2007 and 2011 have been considered for this evaluation.

Project Emissions Baseline 24-Month Period[1]	**2001-2002**
	VOC (ton/yr)
Project Emission Increase (PEI) New Units[2]	202.5
PEI Affected Units[3]	23.1
Coker[5] - Shutdown Heaters	(3.7)
Coker[5] - Shutdown Fugitives	(21.3)
Beavon-Stretford TGU[5] - Shutdown	(0.2)
SBS TGU[5] - Shutdown	(0.1)
SBS Cooling Tower[5] - Shutdown	(0.4)
SRU Incinerator[5] - Shutdown	(0.3)
12PS[5] - Shutdown Heater H-2	(2.6)
12PS[5] - Shutdown Heaters H-1AS/AN	(2.8)
12PS[5] - Shutdown Heater H-1CN	(1.0)
12PS[5] - Shutdown Heater H-1B	(3.9)
12PS[5] - Shutdown Heater H-1CX	(5.1)
No. 4 Treatment Plant[5] - Shutdown Fugitive Components	(0.2)
VRU 300[5] - Shutdown Fugitive Components	(6.2)
PEI	**177.7**

5-Year Contemporaneous Projects

Lakefront FBI Shutdown	(7.3)
Asphalt Infrastructure Project (Increases) (Permit No. 089-24068-00453) (Effective date: 2/20/07)	1.9
Asphalt Infrastructure Project (Decreases)[4] (Submitted: 10/13/06)	(3.8)
Tank Cleaning Project (Permit No. 089-24258-00453) (Effective date: 3/30/2007)	6.8
No. 1 Stanolind Power Station[6] - Shutdown	(8.6)
3UF[6] - Shutdown Heater H-1	(3.7)
3UF[6] - Shutdown Heaters H-2 and F-7	(3.9)
3UF[6,7] - Shutdown Reformer Section	(1.2)
3UF[6] - Shutdown Fugitive Components	(10.8)
Marine Dock[8] - Install VRU or VCU	(175.4)
Tank BT-002 Modification	0.6
Boiler Project	27.2
SCR	5.6
Fire Pump Engines	0.7
Thermal Desorption	2.4
Tank 8	6.1
Tank 3637	0.2
11A PS WARP	2.2
11C PS WARP	(3.9)
FCU500 WARP	1.0
FCU600 WARP	(1.5)
FCU600 TAR	0.3
VRU100/200 WARP	(0.2)
LDAR - Control Existing Heavy Liquid Pumps	(27.3)

NEI Project Emissions	**-14.8**
NSR SERs (tpy)	**25.0**
Significant Net Emissions Increase?	No
Pollutant	**VOC (ton/yr)**

[1] Selected 24-month period is based on calendar years.
[2] PEI New Units from Table C.81.
[3] PEI Affected Units from "Evaluation of Project Impacts on Existing Units" (Tables C.71 through C.80)
[4] Emissions decreases for past contemporaneous projects are being made enforceable as part of the CXHO Project. The emissions decreases were documented in the respective permit applications.
[5] Unit shutdown values based on average past actual emissions for baseline period.
[6] Unit shutdown values for future non-CXHO contemporaneous projects are based on a 24-month period average past actual emissions.
[7] 3UF Reformer emissions based on data recorded by BP Whiting PI data collection system.
[8] Marine Dock VOC emissions based on 2003-2004 total average emissions controlled to 10 mg of VOC/L of throughput for gasoline loading.

Table C.84. PM_{10} (filterable) SIP Limits

Process Heaters and Boilers

Code	Process Unit	Rated Capacity[3]	PM_{10} SIP Limits		Annualized PM_{10} SIP Emissions
			lb/MMBtu	lb/hr	ton/yr
Crude and Coking					
11A PS					
Oth	H-1X	250	0.031	6.867	30.1
Oth	H-2	45	0.032	1.440	6.3
Oth	H-3	55	0.031	1.704	7.5
11C PS					
Oth	H-200	249.5	0.032	7.866	34.5
Oth	H-300	180	0.031	4.931	21.6
Coker					
SD	H-101	200	0.004	0.741	3.2
SD	H-102				
SD	H-103				
SD	H-104				
12PS					
SD	H-1AN	121.5	0.025	16.348	71.6
SD	H-1AS	121.5			
Oth	H-1B	243			
SD	H-2	174			
SD	H-1CN	120	0.004	0.444	1.9
Oth	H-1CX	410	0.004	0.924	4.0
Hydroprocessing					
3UF					
Mod	H-1[4]	240	0.004	0.852	3.7
SD	H-2	185	0.004	0.685	3.0
SD	F-7	23	0.004	0.085	0.4
4UF					
Oth	F-1	68	0.004	1.459	6.4
Oth	F-8A	163			
Oth	F-8B	163			
Oth	F-2	286	0.004	1.059	4.6
Oth	F-3	242	0.004	0.896	3.9
Oth	F-4	137	0.004	1.060	4.6
Oth	F-5	99			
Oth	F-6	49			
Oth	F-7	52	0.004	0.159	0.7
ARU					
Oth	F-200A	249.5	0.004	0.924	4.0
Oth	F-200B	249.5	0.004	0.924	4.0
BOU					
Oth	F-401	35	0.004	0.130	0.6
CFHU					
Oth	F-801A	66.5	0.004	0.246	1.1
Oth	F-801B				
Oth	F-801C	60.00			
CRU					
Oth	F-101	72	0.004	0.267	1.2
Oth	F-102	60	0.004	0.290	1.3
DDU					
Oth	WB-301	64.8	0.004	0.250	1.1
Oth	WB-302	83.7	0.004	0.240	1.1
ISOM					
Mod	H-1	190	0.004	0.704	3.1
HU					
Oth	B-501	366.3	0.009	3.340	14.6
Utilities					
1SPS					
SD	Boiler 3	265	0.016	15.809	69.2
SD	Boiler 4	265			
SD	Boiler 5	265	0.016	13.224	57.9
SD	Boiler 6	265			
SD	Boiler 7	265			
Fluidized Catalytic Cracking[1]					
Oth	FCU 500	115 bbl/day	1.220	73.20	320.6
Mod[5]	FCU 600	80 bbl/day	1.10	55.00	240.9
Sulfur Recovery Complex[2]					
SD	Beavon-Stretford TGU	24.3	0.110	0.103	0.5

[1] PM_{10} SIP Limit for the FCU 500 and FCU 600 are provided in lb/1,000 lb coke burned, not lb/MMBtu.

[2] PM_{10} SIP Limit for the Beavon-Stretford TGU is provided in lb/ton, not lb/MMBtu.

[3] Rated Capacity from Title V Permit (Permit No. T089-6741-00453)

[4] Rated Capacity for 3UF Heater H-1 based on rated capacity used to establish PM SIP limits.

[5] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Table C.85 Concrete Crushing Emissions

Total Concrete to be Crushed	18,000.0	tons
Total Transfer Points	2	
Hours of Operation per day	10	hours/day
Concrete Processed per day	1,200	tons/day
Concrete Processed per hour	120	tons/hour

Emission Calculation Variables[1]	PM	$PM_{10}/PM_{2.5}$	Unit
Uncontrolled Tertiary Crushing Factor	0.0054	0.0024	lb/Ton
Conveyor Transfer Point Factor	0.0030	0.0011	lb/Ton

Emission Calculation

Concrete Crushing Emissions	PM		PM_{10}		$PM_{2.5}$	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Crushing Emissions	0.6	0.0	0.3	0.0	0.3	0.0
Transfer Emissions	0.4	0.0	0.1	0.0	0.1	0.0
Total	1.0	0.08	0.4	0.03	0.4	0.03

1. Emission Factors from AP-42 Section 11.19.2, Table 11.19.2-2 (August 2004)

Table C.86. Increases and Decreases in Sewer Emissions Components Associated with the CXHO Project

EQUIPMENT TYPE Component Type	UNIT 4UF Modified	ARU Modified	BOU Modified	ISOM Modified	VRU 300 Modified	DDU Modified	DHT Modified	12PS Modified	OSBL Modified	3UF Shutdown	Coker 1 Shutdown	No. 4 TP Shutdown	#1 SPS Shutdown	GOHT New	HU-2 New	Coker 2 New	SRU D-Claus New	SRU E-Claus New	SCOT 1 New	SCOT 2 New	TOTALS
Atmospheric Drain Hub	0	0	0	4	-65	4	0	0	16	-48	-53	-60	0	31	31	80	10	10	0	0	-40
Catch Basin (Pad or Paving Drain)[1]	0	0	0	2	0	2	0	0	8	0	0	0	0	15	15	51	5	5	0	0	102
Inspection Points	0	0	0	0	0	0	0	0	2	0	0	0	0	3	3	4	1	1	0	0	13
Cleanouts	0	0	0	0	0	0	0	0	2	0	0	0	0	4	4	5	1	1	0	0	17
Above Ground Sewer Pump Out Points	0	0	0	0	0	0	0	0	10	0	0	0	0	20	20	24	7	7	0	0	87
Sum of Drains																					**78**
Manhole/Junction Box w/o Vent	0	0	0	0	0	0	0	0	5	0	0	0	0	10	10	45	3	3	0	0	77
Manhole/Junction Box w/ CC and/or Vent	0	0	0	0	0	0	0	0	2	0	0	0	0	3	3	4	1	1	0	0	13
OSBL Manholes Per Unit - Sealed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flare / Degassing/ KO Tanks (ie Above Ground Junction Boxes)	0	0	0	0	0	0	0	0	1	0	0	0	0	2	2	2	1	1	0	0	9
Sealed cover sumps - Gas Traps or other sumps	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	9	0	0	0	0	12
Total Manholes/Junction Boxes/Sealed Sumps																					**111**
Below Grade Oily Water Separator - Fixed Roof	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Below Grade Oily Water Separator - Floating Roof	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OSBL Sumps/OWS Per Unit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total In ground OWS/Sumps																					**0**
Tanks DGO / LGO / Sour Water service	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Above Ground Oil Water Separator Tanks	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	1	0	0	0	0	4
Total Above Ground Tanks																					**4**

Assumptions:

All units will meet Benzene Neshaps Compliance Standards

No COV's will be utilized

Estimated Flow Rates for Oil Water Separator Tanks (Based on Design Flow Rate Data):

Unit	Estimated Flow Rate (MMGPD)	Flow Rate (1,000 liters/day)
OSBL	0.02	75.7
GOHT	0.3	1135.5
Coker 2	0.07	264.95
HU 2	0.015	56.775
Total Flow Rate =		1532.9

Emissions Calculations for Sewer Components

AP-42 Factors - Section 5-1 Petroleum Refining 1/95 - Calculations assume 50% control on drains versus uncontrolled drain emissions in AP-42		No. of Units	Units of 1000 liters of flow per day	Emission Factor Value	Emission Factor Units	Total Emissions (kg/hr)
EMISSION INCREASES						
Drains Controlled[1]		78		0.3	kg/day/unit	1.12
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)		22		0.03	kg/day/unit	0.03
Sealed Manholes		89		0.16	kg/day/unit	0.59
Oil Water Separator and Auxillaries						
	OWS	0		0.024	**kg/1000 liters flow**	0.000
	Slop oil tanks/OW surge tanks				Use Tanks Program	0.00
	OWS Abv Gr (API) Controlled	n/a	1532.9	0.024	**kg/1000 liters flow**	1.533
Subtotal for Emission Increases						3.27
EMISSION DECREASES						
Area Drains Controlled				0.3	kg/day/unit	0.00
Area Drains Uncontrolled				0.7	kg/day/unit	0.00
Process Drains Controlled				0.3	kg/day/unit	0.00
Process Drains Uncontrolled				0.7	kg/day/unit	0.00
Catch Basins Controlled				0.3	kg/day/unit	0.00
Catch Basins Uncontrolled				0.7	kg/day/unit	0.00
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)				0.03	kg/day/unit	0.00
Sealed Manholes				0.16	kg/day/unit	0.00
Junction Boxes/Manholes Uncontrolled				0.7	kg/day/unit	0.00
Oil Water Separator and Auxillaries						
	OWS (API) Controlled			0.024	kg/1000 liters	0.00
	OWS (API) Uncontrolled			0.6	kg/1000 liters	0.00
	Slop oil tanks/OW surge tanks					0.00
	OWS Abv Gr (API) UnControlled			0.6	kg/1000 liters	0.00
	OWS Abv Gr (API) Controlled			0.024	kg/1000 liters	0.00
Subtotal for Emission Decreases						0.00
NET EMISSIONS					kg/hr	3.27
					lb/d	172.85
					lb/yr	63090
					TPY	**31.5**

Notes:

[1] The number of catch basins are provided, but are not included in the total emissions calculations since they are storm water catch basins. Emissions from these catch basins are expected to be negligible in comparison to the other process sewer drains included.

Uncontrolled emissions factors from AP-42 Section 5.1, Table 5.1-3 (January 1995)

Emission Source	VOC Emissions Factor per Component	Units	Source*	Ref.
Uncontrolled Drain	0.69	Kg/day	AP-42 (e.g. 450/650)	Table 5.1-3
Controlled Drain (with water trap – 50% control of AP-42)	0.0145	Kg/hr	BIDa	Pg. 4-9
Sealed Manway Cover (gasketed – 77% of AP-42)	0.022	Kg/hr	BIDb	Pg. 2-23
Uncontrolled Junction Box (same as an Uncontrolled Drain)	0.029	Kg/hr	AP-42 (ref. BIDa)	Pg. 3-27
Controlled Junction Box (with carbon canister to comply with BWON – 5% of AP-42)	0.00145	Kg/hr	BIDa, BWON	Pg. 4-30, 61.349(a)(2)(C)(ii)
Uncontrolled OWS	0.6	Kg/1000 liters	AP-42	Table 5.1-2
Controlled OWS	0.024	Kg/1000 liters	AP-42	Table 5.1-2

*Notes:

BIDa - Background Information Document to Proposed NSPS QQQ, Feb. 1985.

BIDb - Background Information Document to Proposed NSPS QQQ, Dec. 1987.

AP-42 - AP 42, Fifth Edition, Volume I Chapter 5.1 Petroleum Refining, Jan. 1995.

Fugitive Emission Calculations for WARP at 11A Pipestill

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	5	0.5789	0.0013	2.0%	0.0643	95%	100%	0.01
Light Liquid	90	0.1878	0.0037	2.0%	0.6644	95%	100%	0.15
Heavy Liquid	7	0.00051	0.00051	2.0%	0.0036	30%	100%	0.01
Pumps								
Light Liquid	1	0.9630	0.0265	2.0%	0.0452	80%	100%	0.04
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	15	0.0827	0.00013	0.3%	0.0057	30%	100%	0.02
Light Liquid	163	0.0827	0.00013	0.3%	0.0616	30%	100%	0.19
Heavy Liquid	12	0.0827	0.00013	0.3%	0.0045	30%	100%	0.01
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves - Added[3]	1	3.728	0.0985	2.0%	0.1711	98%	100%	0.01
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
Total VOC Emissions Associated with Added Components (tons/yr):								0.45
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	-23	0.1878	0.0037	2.0%	-0.1698	95%	100%	-0.04
Heavy Liquid	-8	0.00051	0.00051	2.0%	-0.0041	30%	100%	-0.01
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	-46	0.0827	0.00013	0.3%	-0.0174	30%	100%	-0.05
Heavy Liquid	-19	0.0827	0.00013	0.3%	-0.0072	30%	100%	-0.02
Total VOC Emissions Associated with Removed Components (tons/yr):								**-0.12**
Past Emissions from Relief Valves - Existing Controlled[3]	47	3.728	0.0985	2.0%	8.0412	90%	100%	3.52
Relief Valves - Existing Controlled[3]	47	3.728	0.0985	2.0%	8.0412	98%	100%	0.70
Emissions Reduction (Future - Past)								-2.82
Total VOC Emissions Associated with Added Components and Additional Controls (tons/yr):								**-2.50**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

[3] There is 1 new relief valve and 47 existing RV's - previously routed to the atmosphere (through the blowdown stack) that are now routed to the DDU flare. The existing RVs were previously controlled with a water spray chamber that is presumed to be capable of 90% control.

Increased Sewer Emissions from 11A WARP Project due to Added Equipment

EQUIPMENT TYPE	UNIT 11A PS - Estimated Counts
Atmospheric Drain Hub	15
Catch Basin (Pad or Paving Drain)	6
Inspection Points	7
Cleanouts	6
Above Ground Sewer Pump Out Points	
Sum of Drains	**34**
Manhole/Junction Box w/o Vent	
Manhole/Junction Box w/ CC and/or Vent	
OSBL Manholes Per Unit - Sealed	
Flare / Degassing/ KO Tanks (ie Above Ground Junction Boxes)	0
Sealed cover sumps - Gas Traps or other sumps	
Total Manholes/Junction Boxes/Sealed Sumps	**0**
Below Grade Oily Water Separator - Fixed Roof	
Below Grade Oily Water Separator - Floating Roof	
OSBL Sumps/OWS Per Unit	
Total In ground OWS/Sumps	**0**
Tanks DGO / LGO / Sour Water service	
Above Ground Oil Water Separator Tanks	
Total Above Ground Tanks	**0**

Does Not include Above ground pump out lines as are typically fugitive emissions included with fugitives

Assumptions:
All units will meet Benzene Neshaps Compliance Standards
No COV's will be utilized

AP-42 Factors - Section 5-1 Petroleum Refining 1/95 - Calculations assume 50% control on drains versus uncontrolled drain emissions in AP-42	No. of Units	Units of 1000 liters of flow	Emission Factor Value	Emission Factor Units	Total Emissions (kg/hr)
EMISSION INCREASES					
Drains Controlled	34		0.3	kg/day/unit	0.49
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)	0		0.03	kg/day/unit	0.00
Sealed Manholes	0		0.16	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS	0		0.024	**kg/1000 liters flow**	0.000
Slop oil tanks/OW surge tanks				Use Tanks Program	0.00
OWS Abv Gr (API) Controlled	0		0.024	**kg/1000 liters flow**	0.000
Subtotal for Emission Increases					0.49

EMISSION DECREASES					
Area Drains Controlled			0.3	kg/day/unit	0.00
Area Drains Uncontrolled			0.7	kg/day/unit	0.00
Process Drains Controlled			0.3	kg/day/unit	0.00
Process Drains Uncontrolled			0.7	kg/day/unit	0.00
Catch Basins Controlled			0.3	kg/day/unit	0.00
Catch Basins Uncontrolled			0.7	kg/day/unit	0.00
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)			0.03	kg/day/unit	0.00
Sealed Manholes			0.16	kg/day/unit	0.00
Junction Boxes/Manholes Uncontrolled			0.7	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS (API) Controlled			0.024	kg/1000 liters	0.00
OWS (API) Uncontrolled			0.6	kg/1000 liters	0.00
Slop oil tanks/OW surge tanks					0.00
OWS Abv Gr (API) UnControlled			0.6	kg/1000 liters	0.00
OWS Abv Gr (API) Controlled			0.024	kg/1000 liters	0.00
Subtotal for Emission Decreases					0.00

NET EMISSIONS

kg/hr	0.49
lb/d	25.89
lb/yr	9451
TPY	**4.7**

Notes:

Emission Source		Units	Source*
Uncontrolled Drain	0.69	Kg/day	AP-42 (e.g. 450/650)
Controlled Drain (with water trap – 50% control of AP-42)	0.0145	Kg/hr	BIDa
Sealed Manway Cover (gasketed – 77% of AP-42)	0.022	Kg/hr	BIDb
Uncontrolled Junction Box (same as an Uncontrolled Drain)	0.029	Kg/hr	AP-42 (ref. BIDa)
Controlled Junction Box (with carbon canister to comply with BWON – 5% of AP-42)	0.00145	Kg/hr	BIDa, BWON
Uncontrolled OWS	0.6	Kg/1000 liters	AP-42
Controlled OWS	0.024	Kg/1000 liters	AP-42

*Notes:
BIDa - Background Information Document to Proposed NSPS QQQ, Feb. 1985.
BIDb - Background Information Document to Proposed NSPS QQQ, Dec. 1987.
AP-42 - AP 42, Fifth Edition, Volume I Chapter 5.1 Petroleum Refining, Jan. 1995.

Process Unit	Malfunction Rates		HHV	Sulfur	Frequency/	Duration	VOC				NO_X				SO_2				PM				$PM_{10}/PM_{2.5}$				CO				Pb				Hg				Be			
			BTU/scf	ppm	#/year	hours	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/day[1]	tpy	EF	Unit	lb/day[1]	tpy
AZ-29	0.2466	MMscfh	4,420	1,000	2.0	0.33					0.068	lb/MMBtu	24.7	0.02	see below[2]		13.7	0.01	1.9	lb/MMscf	0.68	0.00	7.6	lb/MMscf	2.71	0.00	0.37	lb/MMBtu	134.4	0.13	5.0E-04	lb/MMscf	1.8E-04	1.78E-07	1.84E-04	lb/MMscf	6.5E-05	6.54E-08	1.20E-05	lb/MMscf	4.3E-06	4.27E-09
AZ-509	0.0356	MMscfh	4,000	150,000	1.0	0.33					0.068	lb/MMBtu	3.2	0.00	see below[2]		295.8	0.15	1.9	lb/MMscf	0.09	0.00	7.6	lb/MMscf	0.35	0.00	0.37	lb/MMBtu	17.6	0.01	5.0E-04	lb/MMscf	2.3E-05	1.16E-08	1.84E-04	lb/MMscf	8.5E-06	4.27E-09	1.20E-05	lb/MMscf	5.6E-07	2.79E-10
AZ-575/AZ-578	0.8331	MMscfh	5,060	1,000	1.0	0.33					0.068	lb/MMBtu	95.6	0.05	see below[2]		46.1	0.02	1.9	lb/MMscf	2.62	0.00	7.6	lb/MMscf	10.47	0.01	0.37	lb/MMBtu	519.9	0.26	5.0E-04	lb/MMscf	6.9E-04	3.44E-07	1.84E-04	lb/MMscf	2.5E-04	1.26E-07	1.20E-05	lb/MMscf	1.7E-05	8.27E-09
AZ-0589	0.1362	MMscfh	1,300	30,000	1.0	0.33					0.068	lb/MMBtu	4.0	0.00	see below[2]		226.3	0.11	1.9	lb/MMscf	0.11	0.00	7.6	lb/MMscf	0.44	0.00	0.37	lb/MMBtu	21.8	0.01	5.0E-04	lb/MMscf	2.9E-05	1.45E-08	1.84E-04	lb/MMscf	1.1E-05	5.31E-09	1.20E-05	lb/MMscf	6.9E-07	3.47E-10

	VOC[3]		NO_X		SO_2		PM		$PM_{10}/PM_{2.5}$		CO		Pb		Hg		Be	
Total Projected Actual Emissions				7.6E-02		0.30		2.1E-03		8.3E-03		0.41		5.5E-07		2.0E-07		1.3E-08
Major New Source Review Thresholds		40		40		40		25		15		100		0.6		0.1		0.1
Major New Source Review Triggered?		No		No		No		No		No		No		No		No		No

[1] Event emission rate represents one worst case emergency/malfunction scenario event. Annual emission rate represents the estimated annual average total duration of worst case emergency/malfunction events.

[2] SO_2 Emissions Calculation:

SO2 MW (lb/lb-mole)=	64

SO2 emissions are calculated based on the concentration of sulfur in the gas stream, the ideal gas law, and the molecular weight of SO2.

General Assumptions Used in Calculations

Variable	Value	Units
V	1,000,000	ft^3
P	14.7	psia
R	10.73	psia-ft^3/lbmol-R
T	527.7	R
md	2596.15	lbmols/MMscf
	385.1851	scf/lbmol

Ideal Gas Law used to determine the moles of gas per MSCF (P*V=n*R*T)

[3] Note that VOC emissions will actually decrease with respect to the current scenario where releases are not vented to the Flare since they will be controlled by the Flare; therefore, the potential VOC emissions associated with emergencies and malfunctions will decrease. Refer to the application text for more information.

Other Notes:

- Natural gas Higher Heating Value (Btu/scf) = 1020
- The 11A WARP project ties existing blowdown RVs to the DDU Flare header system and consists of emergency RVs only. Nitrogen will be used as the purge gas for the new header tie-ins.
- No modifications to the flare, flare knockout drum, or piping from the knockout drum to the flare required modifications to accommodate the worst case emergency relief scenarios when considering the worst case relief scenarios for the current operations
- Regulatory applicability for 40 CFR 63, Subpart CC will not change as a result of the project. Emergency RVs are not miscellaneous process vents per 40 CFR 63, Subpart CC since they are exempted from the definition in 40 CFR 63.641
- RV release gas combustion emission factors for PM/PM10/PM2.5, Lead, Mercury, and Beryllium are from AP-42 Section 1.4 (July 1998). Emission factors for VOC, NOx, and CO are from AP-42 Section 13.5 (September 1991). The emissions for SO2 are calculated
- The HHV and sulfur content was conservatively estimated based on the range of material that could be released. It was also conservatively assumed that each RV would lift one time per year, although this is an unlikely scenario.

Fugitive Emission Calculations for WARP at 11C Pipestill

Note that these counts also include work to control RVs for the 11B Coker that are part of the 11C WARP Project.

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	1	0.5789	0.0013	2.0%	0.0129	95%	100%	0.00
Light Liquid	51	0.1878	0.0037	2.0%	0.3765	95%	100%	0.08
Heavy Liquid	33	0.00051	0.00051	2.0%	0.0168	30%	100%	0.05
Pumps								
Light Liquid	2	0.9630	0.0265	2.0%	0.0905	80%	100%	0.08
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	10	0.0827	0.00013	0.3%	0.0038	30%	100%	0.01
Light Liquid	135	0.0827	0.00013	0.3%	0.0510	30%	100%	0.16
Heavy Liquid	71	0.0827	0.00013	0.3%	0.0268	30%	100%	0.08
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves - Added[3]	0	3.728	0.0985	2.0%	0.0000	98%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
Total VOC Emissions Associated with Added Components (tons/yr):								0.47
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	-6	0.1878	0.0037	2.0%	-0.0443	95%	100%	-0.01
Heavy Liquid	-2	0.00051	0.00051	2.0%	-0.0010	30%	100%	0.00
Flanges								
Gas/Vapor	-2	0.0827	0.00013	0.3%	-0.0008	30%	100%	0.00
Light Liquid	-34	0.0827	0.00013	0.3%	-0.0128	30%	100%	-0.04
Heavy Liquid	-7	0.0827	0.00013	0.3%	-0.0026	30%	100%	-0.01
Total VOC Emissions Associated with Removed Components (tons/yr):								**-0.06**
Past Emissions from Relief Valves - Existing Controlled[3]	77	3.728	0.0985	2.0%	13.1739	90%	100%	5.77
Relief Valves - Existing Controlled[3]	77	3.728	0.0985	2.0%	13.1739	98%	100%	1.15
Emissions Reduction (Future - Past)								-4.62
Total VOC Emissions Associated with Added Components and Additional Controls (tons/yr):								**-4.21**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

[3] There are 2 new relief valves and 74 existing RV's - previously routed to the atmosphere (through the blowdown stack) that are now routed to the DDU flare. The existing RVs were previously controlled with a water spray chamber that is presumed to be capable of 90% control.

Increased Sewer Emissions from 11C WARP Project due to Added Equipment

EQUIPMENT TYPE	UNIT 11C PS - Estimated Counts
Atmospheric Drain Hub	2
Catch Basin (Pad or Paving Drain)	0
Inspection Points	0
Cleanouts	0
Above Ground Sewer Pump Out Points	
Sum of Drains	**2**
Manhole/Junction Box w/o Vent	
Manhole/Junction Box w/ CC and/or Vent	
OSBL Manholes Per Unit - Sealed	
Flare / Degassing/ KO Tanks (ie Above Ground Junction Boxes)	0
Sealed cover sumps - Gas Traps or other sumps	
Total Manholes/Junction Boxes/Sealed Sumps	**0**
Below Grade Oily Water Separator - Fixed Roof	
Below Grade Oily Water Separator - Floating Roof	
OSBL Sumps/OWS Per Unit	
Total In ground OWS/Sumps	**0**
Tanks DGO / LGO / Sour Water service	
Above Ground Oil Water Separator Tanks	
Total Above Ground Tanks	**0**

Does Not include Above ground pump out lines as are typically fugitive emissions included with fugitives

Assumptions:
All units will meet Benzene Neshaps Compliance Standards
No COV's will be utilized

AP-42 Factors - Section 5-1 Petroleum Refining 1/95 - Calculations assume 50% control on drains versus uncontrolled drain emissions in AP-42	No. of Units	Units of 1000 liters of flow	Emission Factor Value	Emission Factor Units	Total Emissions (kg/hr)
EMISSION INCREASES					
Drains Controlled	2		0.3	kg/day/unit	0.03
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)	0		0.03	kg/day/unit	0.00
Sealed Manholes	0		0.16	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS	0		0.024	**kg/1000 liters flow**	0.000
Slop oil tanks/OW surge tanks				Use Tanks Program	0.00
OWS Abv Gr (API) Controlled	0		0.024	**kg/1000 liters flow**	0.000
Subtotal for Emission Increases					0.03

EMISSION DECREASES					
Area Drains Controlled			0.3	kg/day/unit	0.00
Area Drains Uncontrolled			0.7	kg/day/unit	0.00
Process Drains Controlled			0.3	kg/day/unit	0.00
Process Drains Uncontrolled			0.7	kg/day/unit	0.00
Catch Basins Controlled			0.3	kg/day/unit	0.00
Catch Basins Uncontrolled			0.7	kg/day/unit	0.00
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)			0.03	kg/day/unit	0.00
Sealed Manholes			0.16	kg/day/unit	0.00
Junction Boxes/Manholes Uncontrolled			0.7	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS (API) Controlled			0.024	kg/1000 liters	0.00
OWS (API) Uncontrolled			0.6	kg/1000 liters	0.00
Slop oil tanks/OW surge tanks					0.00
OWS Abv Gr (API) UnControlled			0.6	kg/1000 liters	0.00
OWS Abv Gr (API) Controlled			0.024	kg/1000 liters	0.00
Subtotal for Emission Decreases					0.00

NET EMISSIONS

kg/hr	0.03
lb/d	1.52
lb/yr	556
TPY	**0.3**

Notes

Emission Source		Units	Source*
Uncontrolled Drain	0.69	Kg/day	AP-42 (e.g. 450/650)
Controlled Drain (with water trap – 50% control of AP-42)	0.0145	Kg/hr	BIDa
Sealed Manway Cover (gasketed – 77% of AP-42)	0.022	Kg/hr	BIDb
Uncontrolled Junction Box (same as an Uncontrolled Drain)	0.029	Kg/hr	AP-42 (ref. BIDa)
Controlled Junction Box (with carbon canister to comply with BWON – 5% of AP-42)	0.00145	Kg/hr	BIDa, BWON
Uncontrolled OWS	0.6	Kg/1000 liters	AP-42
Controlled OWS	0.024	Kg/1000 liters	AP-42

*Notes:
BIDa - Background Information Document to Proposed NSPS QQQ, Feb. 1985.
BIDb - Background Information Document to Proposed NSPS QQQ, Dec. 1987.
AP-42 - AP 42, Fifth Edition, Volume I Chapter 5.1 Petroleum Refining, Jan. 1995.

Note that the work for 11B is associated with the 11C WARP project.

Process			HHV	Sulfur	Frequency	Duration	VOC				NO_x				SO_2				PM				$PM_{10}/PM_{2.5}$				CO				Pb				Hg				Be			
Unit	Malfunction Rates		BTU/scf	ppm	#/year	hours	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/day[1]	tpy	EF	Unit	lb/day[1]	tpy
C-178	0.0056525	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		9.4	0.00	1.9	lb/MMscf	0.01	0.00	7.6	lb/MMscf	0.06	0.00	0.37	lb/MMBtu	2.8	0.00	5.0E-04	lb/MMscf	3.7E-06	1.85E-09	1.84E-04	lb/MMscf	1.4E-06	6.78E-10	1.20E-05	lb/MMscf	8.9E-08	4.43E-11
C-176	0.0056525	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		9.4	0.00	1.9	lb/MMscf	0.01	0.00	7.6	lb/MMscf	0.06	0.00	0.37	lb/MMBtu	2.8	0.00	5.0E-04	lb/MMscf	3.7E-06	1.85E-09	1.84E-04	lb/MMscf	1.4E-06	6.78E-10	1.20E-05	lb/MMscf	8.9E-08	4.43E-11
C-34B	0.0157137	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	1.4	0.00	see below[2]		26.1	0.01	1.9	lb/MMscf	0.04	0.00	7.6	lb/MMscf	0.16	0.00	0.37	lb/MMBtu	7.8	0.00	5.0E-04	lb/MMscf	1.0E-05	5.14E-09	1.84E-04	lb/MMscf	3.8E-06	1.89E-09	1.20E-05	lb/MMscf	2.5E-07	1.23E-10
C-220	0.0381619	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	3.5	0.00	see below[2]		63.4	0.03	1.9	lb/MMscf	0.09	0.00	7.6	lb/MMscf	0.38	0.00	0.37	lb/MMBtu	18.8	0.01	5.0E-04	lb/MMscf	2.5E-05	1.25E-08	1.84E-04	lb/MMscf	9.2E-06	4.58E-09	1.20E-05	lb/MMscf	6.0E-07	2.99E-10
C-199	0.0022759	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		3.8	0.00	1.9	lb/MMscf	0.01	0.00	7.6	lb/MMscf	0.02	0.00	0.37	lb/MMBtu	1.1	0.00	5.0E-04	lb/MMscf	1.5E-06	7.44E-10	1.84E-04	lb/MMscf	5.5E-07	2.73E-10	1.20E-05	lb/MMscf	3.6E-08	1.79E-11
C-191	0.0008182	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		1.4	0.00	1.9	lb/MMscf	0.00	0.00	7.6	lb/MMscf	0.01	0.00	0.37	lb/MMBtu	0.4	0.00	5.0E-04	lb/MMscf	5.3E-07	2.67E-10	1.84E-04	lb/MMscf	2.0E-07	9.82E-11	1.20E-05	lb/MMscf	1.3E-08	6.42E-12
C-194	0.0055694	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		9.3	0.00	1.9	lb/MMscf	0.01	0.00	7.6	lb/MMscf	0.06	0.00	0.37	lb/MMBtu	2.7	0.00	5.0E-04	lb/MMscf	3.6E-06	1.82E-09	1.84E-04	lb/MMscf	1.3E-06	6.68E-10	1.20E-05	lb/MMscf	8.7E-08	4.37E-11
C-192	0.0055694	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		9.3	0.00	1.9	lb/MMscf	0.01	0.00	7.6	lb/MMscf	0.06	0.00	0.37	lb/MMBtu	2.7	0.00	5.0E-04	lb/MMscf	3.6E-06	1.82E-09	1.84E-04	lb/MMscf	1.3E-06	6.68E-10	1.20E-05	lb/MMscf	8.7E-08	4.37E-11
C-174	0.0033694	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.3	0.00	see below[2]		5.6	0.00	1.9	lb/MMscf	0.01	0.00	7.6	lb/MMscf	0.03	0.00	0.37	lb/MMBtu	1.7	0.00	5.0E-04	lb/MMscf	2.2E-06	1.10E-09	1.84E-04	lb/MMscf	8.1E-07	4.04E-10	1.20E-05	lb/MMscf	5.3E-08	2.64E-11
C-206	0.0003182	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.0	0.00	see below[2]		0.5	0.00	1.9	lb/MMscf	0.00	0.00	7.6	lb/MMscf	0.00	0.00	0.37	lb/MMBtu	0.2	0.00	5.0E-04	lb/MMscf	2.1E-07	1.04E-10	1.84E-04	lb/MMscf	7.6E-08	3.82E-11	1.20E-05	lb/MMscf	5.0E-09	2.50E-12
C-204	0.0018602	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		3.1	0.00	1.9	lb/MMscf	0.00	0.00	7.6	lb/MMscf	0.02	0.00	0.37	lb/MMBtu	0.9	0.00	5.0E-04	lb/MMscf	1.2E-06	6.08E-10	1.84E-04	lb/MMscf	4.5E-07	2.23E-10	1.20E-05	lb/MMscf	2.9E-08	1.46E-11
C-122	0.0340966	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	3.1	0.00	see below[2]		56.7	0.03	1.9	lb/MMscf	0.08	0.00	7.6	lb/MMscf	0.34	0.00	0.37	lb/MMBtu	16.8	0.01	5.0E-04	lb/MMscf	2.2E-05	1.11E-08	1.84E-04	lb/MMscf	8.2E-06	4.09E-09	1.20E-05	lb/MMscf	5.3E-07	2.67E-10
C-160	0.0143992	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	1.3	0.00	see below[2]		23.9	0.01	1.9	lb/MMscf	0.04	0.00	7.6	lb/MMscf	0.14	0.00	0.37	lb/MMBtu	7.1	0.00	5.0E-04	lb/MMscf	9.4E-06	4.71E-09	1.84E-04	lb/MMscf	3.5E-06	1.73E-09	1.20E-05	lb/MMscf	2.3E-07	1.13E-10
C-205	0.0346873	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	3.1	0.00	see below[2]		57.6	0.03	1.9	lb/MMscf	0.09	0.00	7.6	lb/MMscf	0.34	0.00	0.37	lb/MMBtu	17.1	0.01	5.0E-04	lb/MMscf	2.3E-05	1.13E-08	1.84E-04	lb/MMscf	8.3E-06	4.16E-09	1.20E-05	lb/MMscf	5.4E-07	2.72E-10

	VOC[3]		NO_x		SO_2		PM		$PM_{10}/PM_{2.5}$		CO		Pb		Hg		Be	
Total Projected Actual Emissions				7.6E-03		0.14		2.1E-04		8.4E-04		0.04		5.5E-08		2.0E-08		1.3E-09
Major New Source Review Thresholds		40		40		40		25		15		100		0.6		0.1		0.1
Major New Source Review Triggered?		No		No		No		No		No		No		No		No		No

[1] Event emission rate represents one worst case emergency/malfunction scenario event. Annual emission rate represents the estimated annual average total duration of worst case emergency/malfunction events.

[2] SO_2 Emissions Calculation:

SO2 MW (lb/lb-mole)=	64

SO2 emissions are calculated based on the concentration of sulfur in the gas stream, the ideal gas law, and the molecular weight of SO2.

General Assumptions Used in Calculations

Variable	Value	Units
V	1,000,000	ft^3
P	14.7	psia
R	10.73	psia-ft^3/lbmol-R
T	527.7	R
md	2596.15	lbmols/MMscf
	385.1851	scf/lbmol

Ideal Gas Law used to determine the moles of gas per MSCF (P*V=n*R*T)

[3] Note that VOC emissions will actually decrease with respect to the current scenario where releases are not vented to the Flare since they will be controlled by the Flare; therefore, the potential VOC emissions associated with emergencies and malfunctions will decrease. Refer to the application text for more information.

Other Notes:

- Natural gas Higher Heating Value (Btu/scf) = 1020
- The 11B WARP project ties existing blowdown RVs to the DDU Flare header system and consists of emergency RVs only. Nitrogen will be used as the purge gas for the new header tie-ins.
- No modifications to the flare, flare knockout drum, or piping from the knockout drum to the flare required modifications to accommodate the worst case emergency relief scenarios when considering the worst case relief scenarios for the current operations
- Regulatory applicability for 40 CFR 63, Subpart CC will not change as a result of the project. Emergency RVs are not miscellaneous process vents per 40 CFR 63, Subpart CC since they are exempted from the definition in 40 CFR 63.641
- RV release gas combustion emission factors for PM/PM10/PM2.5, Lead, Mercury, and Beryllium are from AP-42 Section 1.4 (July 1998). Emission factors for VOC, NOx, and CO are from AP-42 Section 13.5 (September 1991). The emissions for SO2 are calculated
- The HHV and sulfur content was conservatively estimated based on the range of material that could be released. It was also conservatively assumed that each RV would lift one time per year, although this is an unlikely scenario.

Process Unit	Malfunction Rates		HHV	Sulfur	Frequency	Duration	VOC				NO_x				SO_2				PM				$PM_{10}/PM_{2.5}$				CO				Pb				Hg				Be			
			BTU/scf	ppm	#/year	hours	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/day[1]	tpy	EF	Unit	lb/day[1]	tpy
Z-168	0.0054585	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.9	0.00	5.0E-04	lb/MMscf	1.2E-06	5.80E-10	1.84E-04	lb/MMscf	4.3E-07	2.13E-10	1.20E-05	lb/MMscf	2.8E-08	1.39E-11
Z-203	0.0026753	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.1	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.4	0.00	5.0E-04	lb/MMscf	5.7E-07	2.84E-10	1.84E-04	lb/MMscf	2.1E-07	1.04E-10	1.20E-05	lb/MMscf	1.4E-08	6.82E-12
Z-242	0.0061985	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.0	0.00	5.0E-04	lb/MMscf	1.3E-06	6.58E-10	1.84E-04	lb/MMscf	4.8E-07	2.42E-10	1.20E-05	lb/MMscf	3.2E-08	1.58E-11
Z-154	0.0045804	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.7	0.00	5.0E-04	lb/MMscf	9.7E-07	4.86E-10	1.84E-04	lb/MMscf	3.6E-07	1.79E-10	1.20E-05	lb/MMscf	2.3E-08	1.17E-11
Z-145	0.0102079	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.3	0.00	see below[2]		0.6	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.6	0.00	5.0E-04	lb/MMscf	2.2E-06	1.08E-09	1.84E-04	lb/MMscf	8.0E-07	3.98E-10	1.20E-05	lb/MMscf	5.2E-08	2.60E-11
Z-205	0.0029595	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.2	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.5	0.00	5.0E-04	lb/MMscf	6.3E-07	3.14E-10	1.84E-04	lb/MMscf	2.3E-07	1.15E-10	1.20E-05	lb/MMscf	1.5E-08	7.54E-12
Z-237	0.0029595	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.2	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.5	0.00	5.0E-04	lb/MMscf	6.3E-07	3.14E-10	1.84E-04	lb/MMscf	2.3E-07	1.15E-10	1.20E-05	lb/MMscf	1.5E-08	7.54E-12
Z-140	0.2226303	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	6.6	0.00	see below[2]		12.3	0.01	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	0.7	0.00	0.37	lb/MMBtu	35.7	0.02	5.0E-04	lb/MMscf	4.7E-05	2.36E-08	1.84E-04	lb/MMscf	1.7E-05	8.68E-09	1.20E-05	lb/MMscf	1.1E-06	5.67E-10
Z-218	0.302738	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	8.9	0.00	see below[2]		16.8	0.01	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	1.0	0.00	0.37	lb/MMBtu	48.5	0.02	5.0E-04	lb/MMscf	6.4E-05	3.22E-08	1.84E-04	lb/MMscf	2.4E-05	1.18E-08	1.20E-05	lb/MMscf	1.5E-06	7.72E-10
Z-217	0.0102227	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.3	0.00	see below[2]		0.6	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.6	0.00	5.0E-04	lb/MMscf	2.2E-06	1.09E-09	1.84E-04	lb/MMscf	8.0E-07	3.99E-10	1.20E-05	lb/MMscf	5.2E-08	2.61E-11
Z-216	0.0069113	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.4	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.1	0.00	5.0E-04	lb/MMscf	1.5E-06	7.34E-10	1.84E-04	lb/MMscf	5.4E-07	2.70E-10	1.20E-05	lb/MMscf	3.5E-08	1.76E-11
Z-221	0.0094034	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.3	0.00	see below[2]		0.5	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.5	0.00	5.0E-04	lb/MMscf	2.0E-06	9.99E-10	1.84E-04	lb/MMscf	7.3E-07	3.67E-10	1.20E-05	lb/MMscf	4.8E-08	2.40E-11
Z-207	0.0054217	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.9	0.00	5.0E-04	lb/MMscf	1.2E-06	5.76E-10	1.84E-04	lb/MMscf	4.2E-07	2.11E-10	1.20E-05	lb/MMscf	2.8E-08	1.38E-11
Z-202	0.0045351	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.7	0.00	5.0E-04	lb/MMscf	9.6E-07	4.82E-10	1.84E-04	lb/MMscf	3.5E-07	1.77E-10	1.20E-05	lb/MMscf	2.3E-08	1.16E-11
Z-225	0.007647	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.4	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.2	0.00	5.0E-04	lb/MMscf	1.6E-06	8.12E-10	1.84E-04	lb/MMscf	6.0E-07	2.98E-10	1.20E-05	lb/MMscf	3.9E-08	1.95E-11
Z-204	0.0057253	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.9	0.00	5.0E-04	lb/MMscf	1.2E-06	6.08E-10	1.84E-04	lb/MMscf	4.5E-07	2.23E-10	1.20E-05	lb/MMscf	2.9E-08	1.46E-11
Z-228	0.202389	MMscfh	1,300	400,000	1.0	0.33					0.068	lb/MMBtu	6.0	0.00	see below[2]		4483.7	2.24	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	0.7	0.00	0.37	lb/MMBtu	32.4	0.02	5.0E-04	lb/MMscf	4.3E-05	2.15E-08	1.84E-04	lb/MMscf	1.6E-05	7.89E-09	1.20E-05	lb/MMscf	1.0E-06	5.16E-10
Z-139	0.0091026	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.3	0.00	see below[2]		0.5	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.5	0.00	5.0E-04	lb/MMscf	1.9E-06	9.67E-10	1.84E-04	lb/MMscf	7.1E-07	3.55E-10	1.20E-05	lb/MMscf	4.6E-08	2.32E-11
Z-241	0.0029595	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.2	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.5	0.00	5.0E-04	lb/MMscf	6.3E-07	3.14E-10	1.84E-04	lb/MMscf	2.3E-07	1.15E-10	1.20E-05	lb/MMscf	1.5E-08	7.54E-12
Z-101	0.2560707	MMscfh	1,300	30,000	1.0	0.33					0.068	lb/MMBtu	7.5	0.00	see below[2]		425.5	0.21	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	0.8	0.00	0.37	lb/MMBtu	41.1	0.02	5.0E-04	lb/MMscf	5.4E-05	2.72E-08	1.84E-04	lb/MMscf	2.0E-05	9.99E-09	1.20E-05	lb/MMscf	1.3E-06	6.53E-10
Z-107	0.8227902	MMscfh	4,496	1,000	1.0	0.33					0.068	lb/MMBtu	83.9	0.04	see below[2]		45.6	0.02	1.9	lb/MMscf	2.3	0.00	7.6	lb/MMscf	9.2	0.00	0.37	lb/MMBtu	456.3	0.23	5.0E-04	lb/MMscf	6.0E-04	3.02E-07	1.84E-04	lb/MMscf	2.2E-04	1.11E-07	1.20E-05	lb/MMscf	1.5E-05	7.25E-09
Z-222	0.002347	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.1	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.4	0.00	5.0E-04	lb/MMscf	5.0E-07	2.49E-10	1.84E-04	lb/MMscf	1.8E-07	9.15E-11	1.20E-05	lb/MMscf	1.2E-08	5.98E-12
Z-220	0.0056081	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.9	0.00	5.0E-04	lb/MMscf	1.2E-06	5.96E-10	1.84E-04	lb/MMscf	4.4E-07	2.19E-10	1.20E-05	lb/MMscf	2.9E-08	1.43E-11
Z-114	0.0047881	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.8	0.00	5.0E-04	lb/MMscf	1.0E-06	5.09E-10	1.84E-04	lb/MMscf	3.7E-07	1.87E-10	1.20E-05	lb/MMscf	2.4E-08	1.22E-11
Z-156	0.0036926	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.2	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.6	0.00	5.0E-04	lb/MMscf	7.8E-07	3.92E-10	1.84E-04	lb/MMscf	2.9E-07	1.44E-10	1.20E-05	lb/MMscf	1.9E-08	9.41E-12
Z-116	0.0104647	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.3	0.00	see below[2]		0.6	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.7	0.00	5.0E-04	lb/MMscf	2.2E-06	1.11E-09	1.84E-04	lb/MMscf	8.2E-07	4.08E-10	1.20E-05	lb/MMscf	5.3E-08	2.67E-11
Z-134	0.0021965	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.1	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.4	0.00	5.0E-04	lb/MMscf	4.7E-07	2.33E-10	1.84E-04	lb/MMscf	1.7E-07	8.57E-11	1.20E-05	lb/MMscf	1.1E-08	5.60E-12
Z-121	0.2713905	MMscfh	5,662	1,000	1.0	0.33					0.068	lb/MMBtu	34.8	0.02	see below[2]		15.0	0.01	1.9	lb/MMscf	1.0	0.00	7.6	lb/MMscf	3.8	0.00	0.37	lb/MMBtu	189.5	0.09	5.0E-04	lb/MMscf	2.5E-04	1.26E-07	1.84E-04	lb/MMscf	9.2E-05	4.61E-08	1.20E-05	lb/MMscf	6.0E-06	3.01E-09
Z-132	0.0054392	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.9	0.00	5.0E-04	lb/MMscf	1.2E-06	5.78E-10	1.84E-04	lb/MMscf	4.2E-07	2.12E-10	1.20E-05	lb/MMscf	2.8E-08	1.39E-11

	VOC[3]		NO_x		SO_2		PM		$PM_{10}/PM_{2.5}$		CO		Pb		Hg		Be	
Total Projected Actual Emissions				0.08		2.50		0.00		0.01		0.4		5.5E-07		2.0E-07		1.3E-08
Major New Source Review Thresholds		40		40		40		25		15		100		0.6		0.1		0.1
Major New Source Review Triggered?		N		No		No		No		No		No		No		No		No

[1] Event emission rate represents one worst case emergency/malfunction scenario event. Annual emission rate represents the estimated annual average total duration of worst case emergency/malfunction events.

[2] SO_2 Emissions Calculation:

SO2 MW (lb/lb-mole)=	64

SO2 emissions are calculated based on the concentration of sulfur in the gas stream, the ideal gas law, and the molecular weight of SO2.

General Assumptions Used in Calculations

Variable	Value	Units
V	1,000,000	ft^3
P	14.7	psia
R	10.73	psia-ft^3/lbmol-R
T	527.7	R
md	2596.15	lbmols/MMscf
	385.1851	scf/lbmol

Ideal Gas Law used to determine the moles of gas per MSCF (P*V=n*R*T)

[3] Note that VOC emissions will actually decrease with respect to the current scenario where releases are not vented to the Flare since they will be controlled by the Flare; therefore, the potential VOC emissions associated with emergencies and malfunction

Other Notes:

- Natural gas Higher Heating Value (Btu/scf) = 1020
- The 11C WARP project ties existing blowdown RVs to the DDU Flare header system and consists of emergency RVs only. Nitrogen will be used as the purge gas for the new header tie-ins.
- No modifications to the flare, flare knockout drum, or piping from the knockout drum to the flare required modifications to accommodate the worst case emergency relief scenarios when considering the worst case relief scenarios for the current operations
- Regulatory applicability for 40 CFR 63, Subpart CC will not change as a result of the project. Emergency RVs are not miscellaneous process vents per 40 CFR 63, Subpart CC since they are exempted from the definition in 40 CFR 63.641
- RV release gas combustion emission factors for PM/PM10/PM2.5, Lead, and Mercury are from AP-42 Section 1.4 (July 1998). Emission factors for VOC, NOx, and CO are from AP-42 Section 13.5 (September 1991). The emissions for SO2 are calculated by assumin
- The HHV and sulfur content was conservatively estimated based on the range of material that could be released. It was also conservatively assumed that each RV would lift one time per year, although this is an unlikely scenario.

Fugitive Emission Calculations for WARP at FCU500

Refer to application text for more information regarding FCU 500 WARP and these estimated component counts.

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	93	0.1878	0.0037	2.0%	0.6865	95%	100%	0.15
Heavy Liquid	4	0.00051	0.00051	2.0%	0.0020	30%	100%	0.01
Pumps								
Light Liquid	1	0.9630	0.0265	2.0%	0.0452	80%	100%	0.04
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	1	0.0827	0.00013	0.3%	0.0004	30%	100%	0.00
Light Liquid	192	0.0827	0.00013	0.3%	0.0725	30%	100%	0.22
Heavy Liquid	11	0.0827	0.00013	0.3%	0.0042	30%	100%	0.01
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.43**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Increased Sewer Emissions from FCU500 WARP Project due to Added Equipment

EQUIPMENT TYPE	UNIT FCU500 - Estimated Counts	
Atmospheric Drain Hub	4	
Catch Basin (Pad or Paving Drain)	0	
Inspection Points	0	
Cleanouts	0	
Above Ground Sewer Pump Out Points		
Sum of Drains	**4**	*Does Not include Above ground pump out lines as are typically fugitive emissions included with fugitives*
Manhole/Junction Box w/o Vent		
Manhole/Junction Box w/ CC and/or Vent		
OSBL Manholes Per Unit - Sealed		
Flare / Degassing/ KO Tanks (ie Above Ground Junction Boxes)	0	
Sealed cover sumps - Gas Traps or other sumps		
Total Manholes/Junction Boxes/Sealed Sumps	**0**	
Below Grade Oily Water Separator - Fixed Roof		
Below Grade Oily Water Separator - Floating Roof		
OSBL Sumps/OWS Per Unit		
Total In ground OWS/Sumps	**0**	
Tanks DGO / LGO / Sour Water service		
Above Ground Oil Water Separator Tanks		
Total Above Ground Tanks	**0**	

Assumptions:

All units will meet Benzene Neshaps Compliance Standards

No COV's will be utilized

AP-42 Factors - Section 5-1 Petroleum Refining 1/95 - Calculations assume 50% control on drains versus uncontrolled drain emissions in AP-42	No. of Units	Units of 1000 liters of flow	Emission Factor Value	Emission Factor Units	Total Emissions (kg/hr)
EMISSION INCREASES					
Drains Controlled	4		0.3	kg/day/unit	0.06
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)	0		0.03	kg/day/unit	0.00
Sealed Manholes	0		0.16	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS	0		0.024	**kg/1000 liters flow**	0.000
Slop oil tanks/OW surge tanks				Use Tanks Program	0.00
OWS Abv Gr (API) Controlled	0		0.024	**kg/1000 liters flow**	0.000
Subtotal for Emission Increases					0.06
EMISSION DECREASES					
Area Drains Controlled			0.3	kg/day/unit	0.00
Area Drains Uncontrolled			0.7	kg/day/unit	0.00
Process Drains Controlled			0.3	kg/day/unit	0.00
Process Drains Uncontrolled			0.7	kg/day/unit	0.00
Catch Basins Controlled			0.3	kg/day/unit	0.00
Catch Basins Uncontrolled			0.7	kg/day/unit	0.00
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)			0.03	kg/day/unit	0.00
Sealed Manholes			0.16	kg/day/unit	0.00
Junction Boxes/Manholes Uncontrolled			0.7	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS (API) Controlled			0.024	kg/1000 liters	0.00
OWS (API) Uncontrolled			0.6	kg/1000 liters	0.00
Slop oil tanks/OW surge tanks					0.00
OWS Abv Gr (API) UnControlled			0.024	kg/1000 liters	0.00
OWS Abv Gr (API) Controlled			0.6	kg/1000 liters	0.00
Subtotal for Emission Decreases					0.00

NET EMISSIONS

kg/hr	0.06
lb/d	3.05
lb/yr	1112
TPY	**0.6**

Notes:

Emission Source		Units	Source*
Uncontrolled Drain	0.69	Kg/day	AP-42 (e.g. 450/650)
Controlled Drain (with water trap – 50% control of AP-42)	0.0145	Kg/hr	BIDa
Sealed Manway Cover (gasketed – 77% of AP-42)	0.022	Kg/hr	BIDb
Uncontrolled Junction Box (same as an Uncontrolled Drain)	0.029	Kg/hr	AP-42 (ref. BIDa)
Controlled Junction Box (with carbon canister to comply with BWON – 5% of AP-42)	0.00145	Kg/hr	BIDa, BWON
Uncontrolled OWS	0.6	Kg/1000 liters	AP-42
Controlled OWS	0.024	Kg/1000 liters	AP-42

*Notes:

BIDa - Background Information Document to Proposed NSPS QQQ, Feb. 1985.

BIDb - Background Information Document to Proposed NSPS QQQ, Dec. 1987.

AP-42 - AP 42, Fifth Edition, Volume I Chapter 5.1 Petroleum Refining, Jan. 1995.

Fugitive Emission Calculations for WARP at FCU 600

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	93	0.1878	0.0037	2.0%	0.6865	95%	100%	0.15
Heavy Liquid	4	0.00051	0.00051	2.0%	0.0020	30%	100%	0.01
Pumps								
Light Liquid	1	0.9630	0.0265	2.0%	0.0452	80%	100%	0.04
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	1	0.0827	0.00013	0.3%	0.0004	30%	100%	0.00
Light Liquid	192	0.0827	0.00013	0.3%	0.0725	30%	100%	0.22
Heavy Liquid	11	0.0827	0.00013	0.3%	0.0042	30%	100%	0.01
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves - Added[3]	0	3.728	0.0985	2.0%	0.0000	98%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
Total VOC Emissions Associated with Added Components (tons/yr):								0.43
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	-15	0.1878	0.0037	2.0%	-0.1107	95%	100%	-0.02
Heavy Liquid	-2	0.00051	0.00051	2.0%	-0.0010	30%	100%	0.00
Flanges								
Gas/Vapor	-6	0.0827	0.00013	0.3%	-0.0023	30%	100%	-0.01
Light Liquid	-22	0.0827	0.00013	0.3%	-0.0083	30%	100%	-0.03
Heavy Liquid	-7	0.0827	0.00013	0.3%	-0.0026	30%	100%	-0.01
Total VOC Emissions Associated with Removed Components (tons/yr):								**-0.07**
Past Emissions from Relief Valves - Existing Controlled[3]	41	3.728	0.0985	2.0%	7.0147	90%	100%	3.07
Relief Valves - Existing Controlled[3]	41	3.728	0.0985	2.0%	7.0147	98%	100%	0.61
Emissions Reduction (Future - Past)								-2.46
Total VOC Emissions Associated with Added Components and Additional Controls (tons/yr):								**-2.09**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

[3] There are no new relief valves and 41 existing RV's - previously routed to the atmosphere (through the blowdown stack) that are now routed to the FCU flare. The existing RVs were previously controlled with a water spray chamber that is presumed to be capable of 90% control.

Increased Sewer Emissions from FCU600 WARP Project due to Added Equipment

EQUIPMENT TYPE	UNIT FCU600 - Estimated Counts
Atmospheric Drain Hub	4
Catch Basin (Pad or Paving Drain)	0
Inspection Points	0
Cleanouts	0
Above Ground Sewer Pump Out Points	
Sum of Drains	**4**
Manhole/Junction Box w/o Vent	
Manhole/Junction Box w/ CC and/or Vent	1
OSBL Manholes Per Unit - Sealed	
Flare / Degassing/ KO Tanks (ie Above Ground Junction Boxes)	0
Sealed cover sumps - Gas Traps or other sumps	
Total Manholes/Junction Boxes/Sealed Sumps	**1**
Below Grade Oily Water Separator - Fixed Roof	
Below Grade Oily Water Separator - Floating Roof	
OSBL Sumps/OWS Per Unit	
Total In ground OWS/Sumps	**0**
Tanks DGO / LGO / Sour Water service	
Above Ground Oil Water Separator Tanks	
Total Above Ground Tanks	**0**

Does Not include Above ground pump out lines as are typically fugitive emissions included with fugitives

Assumptions:
All units will meet Benzene Neshaps Compliance Standards
No COV's will be utilized

AP-42 Factors - Section 5-1 Petroleum Refining 1/95 - Calculations assume 50% control on drains versus uncontrolled drain emissions in AP-42	No. of Units	Units of 1000 liters of flow	Emission Factor Value	Emission Factor Units	Total Emissions (kg/hr)
EMISSION INCREASES					
Drains Controlled	4		0.3	kg/day/unit	0.06
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)	0		0.03	kg/day/unit	0.00
Sealed Manholes	0		0.16	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS	0		0.024	**kg/1000 liters flow**	0.000
Slop oil tanks/OW surge tanks				Use Tanks Program	0.00
OWS Abv Gr (API) Controlled	0		0.024	**kg/1000 liters flow**	0.000
Subtotal for Emission Increases					0.06
EMISSION DECREASES					
Area Drains Controlled			0.3	kg/day/unit	0.00
Area Drains Uncontrolled			0.7	kg/day/unit	0.00
Process Drains Controlled			0.3	kg/day/unit	0.00
Process Drains Uncontrolled			0.7	kg/day/unit	0.00
Catch Basins Controlled			0.3	kg/day/unit	0.00
Catch Basins Uncontrolled			0.7	kg/day/unit	0.00
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)			0.03	kg/day/unit	0.00
Sealed Manholes			0.16	kg/day/unit	0.00
Junction Boxes/Manholes Uncontrolled			0.7	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS (API) Controlled			0.024	kg/1000 liters	0.00
OWS (API) Uncontrolled			0.6	kg/1000 liters	0.00
Slop oil tanks/OW surge tanks					0.00
OWS Abv Gr (API) UnControlled			0.024	kg/1000 liters	0.00
OWS Abv Gr (API) Controlled			0.6	kg/1000 liters	0.00
Subtotal for Emission Decreases					0.00

NET EMISSIONS

kg/hr	0.06
lb/d	3.05
lb/yr	1112
TPY	**0.6**

Notes:

Emission Source		Units	Source*
Uncontrolled Drain	0.69	Kg/day	AP-42 (e.g. 450/650)
Controlled Drain (with water trap – 50% control of AP-42)	0.0145	Kg/hr	BIDa
Sealed Manway Cover (gasketed – 77% of AP-42)	0.022	Kg/hr	BIDb
Uncontrolled Junction Box (same as an Uncontrolled Drain)	0.029	Kg/hr	AP-42 (ref. BIDa)
Controlled Junction Box (with carbon canister to comply with BWON – 5% of AP-42)	0.00145	Kg/hr	BIDa, BWON
Uncontrolled OWS	0.6	Kg/1000 liters	AP-42
Controlled OWS	0.024	Kg/1000 liters	AP-42

*Notes:
BIDa - Background Information Document to Proposed NSPS QQQ, Feb. 1985.
BIDb - Background Information Document to Proposed NSPS QQQ, Dec. 1987.
AP-42 - AP 42, Fifth Edition, Volume I Chapter 5.1 Petroleum Refining, Jan. 1995.

RV's	Malfunction Rates		HHV	Sulfur	Frequency/	Duration	VOC				NO_X				SO_2				PM				$PM_{10}/PM_{2.5}$				CO				Pb				Hg				Be			
			BTU/scf	ppm	#/year	hours	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/day[1]	tpy	EF	Unit	lb/day[1]	tpy
R-0041	1.33E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.9	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.4	0.00	5.0E-04	lb/MMscf	3.2E-06	1.59E-09	1.84E-04	lb/MMscf	1.2E-06	5.85E-10	1.20E-05	lb/MMscf	7.6E-08	3.82E-11
R-0045	1.33E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.9	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.4	0.00	5.0E-04	lb/MMscf	3.2E-06	1.59E-09	1.84E-04	lb/MMscf	1.2E-06	5.85E-10	1.20E-05	lb/MMscf	7.6E-08	3.82E-11
R-0049	1.33E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.9	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.4	0.00	5.0E-04	lb/MMscf	3.2E-06	1.59E-09	1.84E-04	lb/MMscf	1.2E-06	5.85E-10	1.20E-05	lb/MMscf	7.6E-08	3.82E-11
R-0047	1.33E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.9	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.4	0.00	5.0E-04	lb/MMscf	3.2E-06	1.59E-09	1.84E-04	lb/MMscf	1.2E-06	5.85E-10	1.20E-05	lb/MMscf	7.6E-08	3.82E-11
R-0048	1.33E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.9	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.4	0.00	5.0E-04	lb/MMscf	3.2E-06	1.59E-09	1.84E-04	lb/MMscf	1.2E-06	5.85E-10	1.20E-05	lb/MMscf	7.6E-08	3.82E-11
R-0051	1.33E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.9	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.4	0.00	5.0E-04	lb/MMscf	3.2E-06	1.59E-09	1.84E-04	lb/MMscf	1.2E-06	5.85E-10	1.20E-05	lb/MMscf	7.6E-08	3.82E-11
R-2099	2.52E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.8	0.00	see below[2]		1.7	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	4.5	0.00	5.0E-04	lb/MMscf	6.0E-06	3.01E-09	1.84E-04	lb/MMscf	2.2E-06	1.10E-09	1.20E-05	lb/MMscf	1.4E-07	7.22E-11
R-2100	2.52E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.8	0.00	see below[2]		1.7	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	4.5	0.00	5.0E-04	lb/MMscf	6.0E-06	3.01E-09	1.84E-04	lb/MMscf	2.2E-06	1.10E-09	1.20E-05	lb/MMscf	1.4E-07	7.22E-11
R-2010	2.74E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.9	0.00	see below[2]		1.8	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	4.9	0.00	5.0E-04	lb/MMscf	6.5E-06	3.27E-09	1.84E-04	lb/MMscf	2.4E-06	1.20E-09	1.20E-05	lb/MMscf	1.6E-07	7.85E-11
R-2011	2.74E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.9	0.00	see below[2]		1.8	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	4.9	0.00	5.0E-04	lb/MMscf	6.5E-06	3.27E-09	1.84E-04	lb/MMscf	2.4E-06	1.20E-09	1.20E-05	lb/MMscf	1.6E-07	7.85E-11
R-2107	2.26E-03	MMscfh	12,338	11,000	1	0.33					0.068	lb/MMBtu	0.6	0.00	see below[2]		1.4	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	3.4	0.00	5.0E-04	lb/MMscf	4.5E-06	2.27E-09	1.84E-04	lb/MMscf	1.7E-06	8.35E-10	1.20E-05	lb/MMscf	1.1E-07	5.46E-11
R-2108	2.26E-03	MMscfh	12,338	11,000	1	0.33					0.068	lb/MMBtu	0.6	0.00	see below[2]		1.4	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	3.4	0.00	5.0E-04	lb/MMscf	4.5E-06	2.27E-09	1.84E-04	lb/MMscf	1.7E-06	8.35E-10	1.20E-05	lb/MMscf	1.1E-07	5.46E-11
R-2069	2.72E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.6	0.00	see below[2]		1.1	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	3.3	0.00	5.0E-04	lb/MMscf	4.4E-06	2.19E-09	1.84E-04	lb/MMscf	1.6E-06	8.05E-10	1.20E-05	lb/MMscf	1.1E-07	5.26E-11
R-2054	2.72E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.6	0.00	see below[2]		1.1	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	3.3	0.00	5.0E-04	lb/MMscf	4.4E-06	2.19E-09	1.84E-04	lb/MMscf	1.6E-06	8.05E-10	1.20E-05	lb/MMscf	1.1E-07	5.26E-11
R-2055	4.09E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.9	0.00	see below[2]		1.6	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	5.0	0.00	5.0E-04	lb/MMscf	6.6E-06	3.30E-09	1.84E-04	lb/MMscf	2.4E-06	1.21E-09	1.20E-05	lb/MMscf	1.6E-07	7.91E-11
R-2004	2.76E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.6	0.00	see below[2]		1.1	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	3.4	0.00	5.0E-04	lb/MMscf	4.4E-06	2.22E-09	1.84E-04	lb/MMscf	1.6E-06	8.17E-10	1.20E-05	lb/MMscf	1.1E-07	5.34E-11
R-2007	1.47E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		1.0	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	2.7	0.00	5.0E-04	lb/MMscf	3.5E-06	1.76E-09	1.84E-04	lb/MMscf	1.3E-06	6.46E-10	1.20E-05	lb/MMscf	8.4E-08	4.22E-11
R-2020	2.65E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.6	0.00	see below[2]		1.0	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	3.2	0.00	5.0E-04	lb/MMscf	4.3E-06	2.14E-09	1.84E-04	lb/MMscf	1.6E-06	7.86E-10	1.20E-05	lb/MMscf	1.0E-07	5.13E-11
R-2053	1.18E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.8	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.1	0.00	5.0E-04	lb/MMscf	2.8E-06	1.40E-09	1.84E-04	lb/MMscf	1.0E-06	5.16E-10	1.20E-05	lb/MMscf	6.7E-08	3.37E-11
R-2070	3.48E-02	MMscfh	12,338	11,000	1	0.33					0.068	lb/MMBtu	9.7	0.00	see below[2]		21.2	0.01	1.9	lb/MMscf	0.3	0.00	7.6	lb/MMscf	1.1	0.00	0.37	lb/MMBtu	52.9	0.03	5.0E-04	lb/MMscf	7.0E-05	3.50E-08	1.84E-04	lb/MMscf	2.6E-05	1.29E-08	1.20E-05	lb/MMscf	1.7E-06	8.41E-10
R-2101	3.57E-02	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	8.0	0.00	see below[2]		13.8	0.01	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	0.9	0.00	0.37	lb/MMBtu	43.5	0.02	5.0E-04	lb/MMscf	5.8E-05	2.88E-08	1.84E-04	lb/MMscf	2.1E-05	1.06E-08	1.20E-05	lb/MMscf	1.4E-06	6.92E-10
R-1023	3.98E-02	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	8.9	0.00	see below[2]		15.4	0.01	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	1.0	0.00	0.37	lb/MMBtu	48.5	0.02	5.0E-04	lb/MMscf	6.4E-05	3.22E-08	1.84E-04	lb/MMscf	2.4E-05	1.18E-08	1.20E-05	lb/MMscf	1.5E-06	7.72E-10
R-0920	1.33E-02	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	4.4	0.00	see below[2]		8.9	0.00	1.9	lb/MMscf	0.1	0.00	7.6	lb/MMscf	0.5	0.00	0.37	lb/MMBtu	24.1	0.01	5.0E-04	lb/MMscf	3.2E-05	1.59E-08	1.84E-04	lb/MMscf	1.2E-05	5.85E-09	1.20E-05	lb/MMscf	7.7E-07	3.83E-10
R-2092	2.66E-02	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	6.0	0.00	see below[2]		10.3	0.01	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	0.7	0.00	0.37	lb/MMBtu	32.5	0.02	5.0E-04	lb/MMscf	4.3E-05	2.15E-08	1.84E-04	lb/MMscf	1.6E-05	7.90E-09	1.20E-05	lb/MMscf	1.0E-06	5.16E-10
R-0926	2.05E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		0.8	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	2.5	0.00	5.0E-04	lb/MMscf	3.3E-06	1.66E-09	1.84E-04	lb/MMscf	1.2E-06	6.08E-10	1.20E-05	lb/MMscf	8.0E-08	3.98E-11
R-0928	2.05E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		0.8	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	2.5	0.00	5.0E-04	lb/MMscf	3.3E-06	1.66E-09	1.84E-04	lb/MMscf	1.2E-06	6.08E-10	1.20E-05	lb/MMscf	8.0E-08	3.98E-11

	VOC[3]		NO_X		SO_2		PM		$PM_{10}/PM_{2.5}$		CO		Pb		Hg		Be	
Total Projected Actual Emissions				0.02		0.05		6.8E-04		2.7E-03		0.1		1.8E-07		6.6E-08		4.3E-09
Major New Source Review Thresholds		40		40		40		25		15		100		0.6		0.1		0.1
Major New Source Review Triggered?		No		No		No		No		No		No		No		No		No

[1] Event emission rate represents one worst case emergency/malfunction scenario event. Annual emission rate represents the estimated annual average total duration of worst case emergency/malfunction events.

[2] SO_2 Emissions Calculation:

SO2 MW (lb/lb-mole)=	64

SO2 emissions are calculated based on the concentration of sulfur in the gas stream, the ideal gas law, and the molecular weight of SO2.

General Assumptions Used in Calculations

Variable	Value	Units
V	1,000,000	ft^3
P	14.7	psia
R	10.73	psia-ft^3/lbmol-R
T	527.7	R
md	2596.15	lbmols/MMscf
	385.1851	scf/lbmol

Ideal Gas Law used to determine the moles of gas per MSCF (P*V=n*R*T)

[3] Note that VOC emissions will actually decrease with respect to the current scenario where releases are not vented to the Flare since they will be controlled by the Flare; therefore, the potential VOC emissions associated with emergencies and malfunctions will decrease. Refer to the application text for more information.

Other Notes:

- Natural gas Higher Heating Value (Btu/sct) = 1020
- The FCU 600 WARP project ties existing blowdown RVs to the FCU Flare header system and consists of emergency RVs only. Nitrogen will be used as the purge gas for the new header tie-ins.
- No modifications to the flare, flare knockout drum, or piping from the knockout drum to the flare required modifications to accommodate the worst case emergency relief scenarios when considering the worst case relief scenarios for the current operations
- Regulatory applicability for 40 CFR 63, Subpart CC will not change as a result of the project. Emergency RVs are not miscellaneous process vents per 40 CFR 63, Subpart CC since they are exempted from the definition in 40 CFR 63.641
- RV release gas combustion emission factors for PM/PM10/PM2.5, Lead, Beryllium, and Mercury are from AP-42 Section 1.4 (July 1998). Emission factors for VOC, NOx, and CO are from AP-42 Section 13.5 (September 1991). The emissions for SO2 are calculated

Fugitive Emission Calculations for FCU600 TAR

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	10	0.5789	0.0013	2.0%	0.1285	95%	100%	0.03
Light Liquid	26	0.1878	0.0037	2.0%	0.1919	95%	100%	0.04
Heavy Liquid	24	0.00051	0.00051	2.0%	0.0122	30%	100%	0.04
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	26	0.0827	0.00013	0.3%	0.0098	30%	100%	0.03
Light Liquid	78	0.0827	0.00013	0.3%	0.0295	30%	100%	0.09
Heavy Liquid	63	0.0827	0.00013	0.3%	0.0238	30%	100%	0.07
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.30**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Fugitive Emission Calculations for WARP at VRU 100

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	1	0.5789	0.0013	2.0%	0.0129	95%	100%	0.00
Light Liquid	15	0.1878	0.0037	2.0%	0.1107	95%	100%	0.02
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	11	0.0827	0.00013	0.3%	0.0042	30%	100%	0.01
Light Liquid	30	0.0827	0.00013	0.3%	0.0113	30%	100%	0.03
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves - Added[3]	0	3.728	0.0985	2.0%	0.0000	98%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
Total VOC Emissions Associated with Added Components (tons/yr):								0.07
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	-5	0.1878	0.0037	2.0%	-0.0369	95%	100%	-0.01
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	-16	0.0827	0.00013	0.3%	-0.0060	30%	100%	-0.02
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Total VOC Emissions Associated with Removed Components (tons/yr):								**-0.03**
Past Emissions from Relief Valves - Existing Controlled[3]	2	3.728	0.0985	2.0%	0.3422	90%	100%	0.15
Relief Valves - Existing Controlled[3]	2	3.728	0.0985	2.0%	0.3422	98%	100%	0.03
Emissions Reduction (Future - Past)								-0.12
Total VOC Emissions Associated with Added Components and Additional Controls (tons/yr):								**-0.07**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

[3] There are no new relief valves and 2existing RV's - previously routed to the atmosphere (through the blowdown stack) that are now routed to the VRU flare. The existing RVs were previously controlled with a water spray chamber that is presumed to be capable of 90% control.

Fugitive Emission Calculations for WARP at VRU 200

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	1	0.5789	0.0013	2.0%	0.0129	95%	100%	0.00
Light Liquid	3	0.1878	0.0037	2.0%	0.0221	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	7	0.0827	0.00013	0.3%	0.0026	30%	100%	0.01
Light Liquid	7	0.0827	0.00013	0.3%	0.0026	30%	100%	0.01
Heavy Liquid	1	0.0827	0.00013	0.3%	0.0004	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves - Added[3]	0	3.728	0.0985	2.0%	0.0000	98%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
Total VOC Emissions Associated with Added Components (tons/yr):								0.03
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	-3	0.1878	0.0037	2.0%	-0.0221	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	-5	0.0827	0.00013	0.3%	-0.0019	30%	100%	-0.01
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Total VOC Emissions Associated with Removed Components (tons/yr):								**-0.01**
Past Emissions from Relief Valves - Existing Controlled[3]	4	3.728	0.0985	2.0%	0.6844	90%	100%	0.30
Relief Valves - Existing Controlled[3]	4	3.728	0.0985	2.0%	0.6844	98%	100%	0.06
Emissions Reduction (Future - Past)								-0.24
Total VOC Emissions Associated with Added Components and Additional Controls (tons/yr):								**-0.23**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

[3] There are no new relief valves and 4 existing RV's - previously routed to the atmosphere (through the blowdown stack) that are now routed to the VRU flare. The existing RVs were previously controlled with a water spray chamber that is presumed to be capable of 90% control.

Increased Sewer Emissions from VRU 100/200 WARP Project due to Added Equipment

EQUIPMENT TYPE	UNIT VRU 100/200 - Estimated Counts
Atmospheric Drain Hub	1
Catch Basin (Pad or Paving Drain)	0
Inspection Points	0
Cleanouts	0
Above Ground Sewer Pump Out Points	
Sum of Drains	**1**
Manhole/Junction Box w/o Vent	
Manhole/Junction Box w/ CC and/or Vent	
OSBL Manholes Per Unit - Sealed	
Flare / Degassing/ KO Tanks (ie Above Ground Junction Boxes)	0
Sealed cover sumps - Gas Traps or other sumps	
Total Manholes/Junction Boxes/Sealed Sumps	**0**
Below Grade Oily Water Separator - Fixed Roof	
Below Grade Oily Water Separator - Floating Roof	
OSBL Sumps/OWS Per Unit	
Total In ground OWS/Sumps	**0**
Tanks DGO / LGO / Sour Water service	
Above Ground Oil Water Separator Tanks	
Total Above Ground Tanks	**0**

Does Not include Above ground pump out lines as are typically fugitive emissions included with fugitives

Assumptions:
All units will meet Benzene Neshaps Compliance Standards
No COV's will be utilized

AP-42 Factors - Section 5-1 Petroleum Refining 1/95 - Calculations assume 50% control on drains versus uncontrolled drain emissions in AP-42	No. of Units	Units of 1000 liters of flow	Emission Factor Value	Emission Factor Units	Total Emissions (kg/hr)
EMISSION INCREASES					
Drains Controlled	1		0.3	kg/day/unit	0.01
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)	0		0.03	kg/day/unit	0.00
Sealed Manholes	0		0.16	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS	0		0.024	**kg/1000 liters flow**	0.000
Slop oil tanks/OW surge tanks				Use Tanks Program	0.00
OWS Abv Gr (API) Controlled	0		0.024	**kg/1000 liters flow**	0.000
Subtotal for Emission Increases					0.01
EMISSION DECREASES					
Area Drains Controlled			0.3	kg/day/unit	0.00
Area Drains Uncontrolled			0.7	kg/day/unit	0.00
Process Drains Controlled			0.3	kg/day/unit	0.00
Process Drains Uncontrolled			0.7	kg/day/unit	0.00
Catch Basins Controlled			0.3	kg/day/unit	0.00
Catch Basins Uncontrolled			0.7	kg/day/unit	0.00
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)			0.03	kg/day/unit	0.00
Sealed Manholes			0.16	kg/day/unit	0.00
Junction Boxes/Manholes Uncontrolled			0.7	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS (API) Controlled			0.024	kg/1000 liters	0.00
OWS (API) Uncontrolled			0.6	kg/1000 liters	0.00
Slop oil tanks/OW surge tanks					0.00
OWS Abv Gr (API) UnControlled			0.024	kg/1000 liters	0.00
OWS Abv Gr (API) Controlled			0.6	kg/1000 liters	0.00
Subtotal for Emission Decreases					0.00

NET EMISSIONS

kg/hr	0.01
lb/d	0.76
lb/yr	278
TPY	**0.1**

Notes:

Emission Source		Units	Source*
Uncontrolled Drain	0.69230769	Kg/day	AP-42 (e.g. 450/650)
Controlled Drain (with water trap – 50% control of AP-42)	0.0145	Kg/hr	BIDa
Sealed Manway Cover (gasketed – 77% of AP-42)	0.022	Kg/hr	BIDb
Uncontrolled Junction Box (same as an Uncontrolled Drain)	0.029	Kg/hr	AP-42 (ref. BIDa)
Controlled Junction Box (with carbon canister to comply with BWON – 5% of AP-42)	0.00145	Kg/hr	BIDa, BWON
Uncontrolled OWS	0.6	Kg/1000 liters	AP-42
Controlled OWS	0.024	Kg/1000 liters	AP-42

*Notes:
BIDa - Background Information Document to Proposed NSPS QQQ, Feb. 1985.
BIDb - Background Information Document to Proposed NSPS QQQ, Dec. 1987.
AP-42 - AP 42, Fifth Edition, Volume I Chapter 5.1 Petroleum Refining, Jan. 1995.

Process Unit	Malfunction Rates		HHV	Sulfur	Frequency	Duration	VOC				NO_X				SO_2				PM				$PM_{10}/PM_{2.5}$				CO				Pb				Hg				Be			
			BTU/scf	ppm	#/year	hours	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/day[1]	tpy	EF	Unit	lb/day[1]	tpy
SV-963	0.00326	MMscfh	12,338	11,000	1.0	0.33					0.068	lb/MMBtu	0.9	0.00	see below[2]		2.0	0.00	1.9	lb/MMscf	0.02	0.00	7.6	lb/MMscf	0.10	0.00	0.37	lb/MMBtu	5.0	0.00	5.0E-04	lb/MMscf	6.6E-06	3.29E-09	1.84E-04	lb/MMscf	2.4E-06	1.21E-09	1.20E-05	lb/MMscf	1.6E-07	7.89E-11
SV-972	0.00660	MMscfh	9,880	7,000	1.0	0.33					0.068	lb/MMBtu	1.5	0.00	see below[2]		2.6	0.00	1.9	lb/MMscf	0.04	0.00	7.6	lb/MMscf	0.16	0.00	0.37	lb/MMBtu	8.0	0.00	5.0E-04	lb/MMscf	1.1E-05	5.33E-09	1.84E-04	lb/MMscf	3.9E-06	1.96E-09	1.20E-05	lb/MMscf	2.6E-07	1.28E-10
T-519	0.01424	MMscfh	9,880	7,000	1.0	0.33					0.068	lb/MMBtu	3.2	0.00	see below[2]		5.5	0.00	1.9	lb/MMscf	0.09	0.00	7.6	lb/MMscf	0.35	0.00	0.37	lb/MMBtu	17.3	0.01	5.0E-04	lb/MMscf	2.3E-05	1.15E-08	1.84E-04	lb/MMscf	8.4E-06	4.22E-09	1.20E-05	lb/MMscf	5.5E-07	2.76E-10
T-528	0.00467	MMscfh	9,880	7,000	1.0	0.33					0.068	lb/MMBtu	1.0	0.00	see below[2]		1.8	0.00	1.9	lb/MMscf	0.03	0.00	7.6	lb/MMscf	0.11	0.00	0.37	lb/MMBtu	5.7	0.00	5.0E-04	lb/MMscf	7.5E-06	3.77E-09	1.84E-04	lb/MMscf	2.8E-06	1.38E-09	1.20E-05	lb/MMscf	1.8E-07	9.05E-11
T-526	0.00242	MMscfh	12,338	11,000	1.0	0.33					0.068	lb/MMBtu	0.7	0.00	see below[2]		1.5	0.00	1.9	lb/MMscf	0.02	0.00	7.6	lb/MMscf	0.07	0.00	0.37	lb/MMBtu	3.7	0.00	5.0E-04	lb/MMscf	4.9E-06	2.44E-09	1.84E-04	lb/MMscf	1.8E-06	8.94E-10	1.20E-05	lb/MMscf	1.2E-07	5.84E-11
T-530	0.00638	MMscfh	9,880	7,000	1.0	0.33					0.068	lb/MMBtu	1.4	0.00	see below[2]		2.5	0.00	1.9	lb/MMscf	0.04	0.00	7.6	lb/MMscf	0.16	0.00	0.37	lb/MMBtu	7.8	0.00	5.0E-04	lb/MMscf	1.0E-05	5.15E-09	1.84E-04	lb/MMscf	3.8E-06	1.89E-09	1.20E-05	lb/MMscf	2.5E-07	1.24E-10

	VOC[3]		NO_X		SO_2		PM		$PM_{10}/PM_{2.5}$		CO		Pb		Hg		Be	
Total Projected Actual Emissions				4.4E-03		0.01		1.2E-04		4.8E-04		0.02		3.1E-08		1.2E-08		7.6E-10
Major New Source Review Thresholds		40		40		40		25		15		100		0.6		0.1		0.1
Major New Source Review Triggered?		No		No		No		No		No		No		No		No		No

[1] Event emission rate represents one worst case emergency/malfunction scenario event. Annual emission rate represents the estimated annual average total duration of worst case emergency/malfunction events.

[2] SO_2 Emissions Calculation:

SO2 MW (lb/lb-mole)=	64

SO2 emissions are calculated based on the concentration of sulfur in the gas stream, the ideal gas law, and the molecular weight of SO2.

General Assumptions Used in Calculations

Variable	Value	Units
V	1,000,000	ft^3
P	14.7	psia
R	10.73	psia-ft^3/lbmol-R
T	527.7	R
md	2596.15	lbmols/MMscf
	385.1851	scf/lbmol

Ideal Gas Law used to determine the moles of gas per MSCF (P*V=n*R*T)

[3] Note that VOC emissions will actually decrease with respect to the current scenario where releases are not vented to the Flare since they will be controlled by the Flare; therefore, the potential VOC emissions associated with emergencies and malfunctions will decrease. Refer to the application text for more information.

Other Notes:

- Natural gas Higher Heating Value (Btu/scf) = 1020
- The VRU WARP project ties existing blowdown RVs to the VRU Flare header system from VRU 100 and VRU 200 and consists of emergency RVs only. Nitrogen will be used as the purge gas for the new header tie-ins.
- No modifications to the flare, flare knockout drum, or piping from the knockout drum to the flare required modifications to accommodate the worst case emergency relief scenarios when considering the worst case relief scenarios for the current operations
- Regulatory applicability for 40 CFR 63, Subpart CC will not change as a result of the project. Emergency RVs are not miscellaneous process vents per 40 CFR 63, Subpart CC since they are exempted from the definition in 40 CFR 63.641
- RV release gas combustion emission factors for PM/PM10/PM2.5, Lead, Beryllium and Mercury are from AP-42 Section 1.4 (July 1998). Emission factors for VOC, NOx, and CO are from AP-42 Section 13.5 (September 1991). The emissions for SO2 are calculated
- It was also conservatively assumed that each RV would lift one time per year, although this is an unlikely scenario.

Fugitive Emission Calculations for TK-3637

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	10	0.1878	0.0037	2.0%	0.0738	95%	100%	0.02
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	22	0.0827	0.00013	0.3%	0.0083	30%	100%	0.03
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.04**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Reference Data

3SPS potential emissions are presented below only for reference for determining the particulate emissions from the SCR. The 3SPS boilers will not be modified for this project since the SCR will be an add-on control.

Process Unit	Maximum Heat Capacity		VOC				NOx				SO2				PM				PM10/PM2.5				CO				Pb			
			EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy
3SPS	2,774	MMBtu/hour									24.45	lb/MMscf	56.4	246.9																
Fired Heater	198	MMBtu/hour	5.5	lb/MMscf	1.1	4.7	0.05	lb/MMBtu	9.89	43.3	26.44	lb/MMscf	4.3	19.0	1.9	lb/MMscf	0.4	1.6	7.6	lb/MMscf	1.5	6.5	0.02	lb/MMBtu	4.0	17.3	5.0E-04	lb/MMscf	9.7E-05	4.2E-04

NOx emissions calculated above are pre-SCR, uncontrolled emissions.

Conversion Rate	3.0%
NOX Reduction (from inlet to SCR)	95%
NSPS J Limit (ppm)	159
TRS Reported in 2005 (ppm)	147
Calculated SO2 Emission Factor at NSPS J Limit (lb/MMscf)	26.44
Calculated SO2 Emission Factor at Current Maximum Average TRS (lb/MMscf)	24.45
Duct Burner ppm sulfur	159.00
Duct Burner SO2 Emission Factor (lb/MMscf)	26.44
Refinery Fuel Gas HHV (BTU/scf)	1203.33
3 SPS Boiler Utilization Factor	0.965

Project Potential to Emit Increase - for permitting level applicability

Conversion to Ammonium Sulfate

Control Device	SO_2 to SO_3 Conversion Rate		VOC				NOx				SO2				PM				PM10/PM2.5				CO				Pb				Sulfuric Acid Mist				Mercury				Beryllium			
			EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy
SCR Impact on Boilers	3.0%	% Conversion Rate	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a					n/a	n/a	3.5	15.3	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Duct Burners	198	MMBtu/hour			1.1	4.7			9.9	43.3			4.3	19.0	1.9	lb/MMscf	0.4	1.6			1.7	7.6			4.0	17.3			0.0	0.0				0.9	1.8E-07	lb/MMBtu	3.6E-05	1.6E-04	1.2E-08	lb/MMBtu	2.3E-06	1.0E-05
Project PTE						4.7				43.3				19.0								22.9				17.3								0.9				1.6E-04				1.0E-05
Project PTE (with NOx controls included)						4.7				2.2				19.0								22.9				17.3																
Part 70 Minor						**2.7**				**4.6**				**10**								**5**				**25**																
Part 70 Significant						**25**				**25**				**25**								**25**				**100**																
Part 70 Permit Required?						**Yes**				**Yes**				**Yes**								**Yes**				**No**																

Project Emissions Increase - for major NSR applicability

Potential 3SPS Gas Usage Rate (based on maximum heat input capacity and utilization factor)	Potential SO2			
MMscf/year	EF	Unit	lb/hr	tpy
20,196.89	24.45	lb/MMscf	n/a	246.9
Potential Duct Burner SO2 Emissions	26.44	lb/MMscf	4.3	19.0
Total Potential SO2 Emissions				265.9

Conversion to Ammonium Sulfate

Control Device	SO_2 to SO_3 Conversion Rate		VOC				NOx				SO2				PM				PM10/PM2.5				CO				Pb				Sulfuric Acid Mist				Mercury				Beryllium			
			EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy
SCR Impact on Boilers	3.0%	% Conversion Rate	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a					n/a	n/a	n/a	15.3	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Duct Burners	198	MMBtu/hour				4.7				2.2				19.0	1.9	lb/MMscf	0.4	1.6				7.6				17.3				0.0	n/a	n/a	n/a	0.87	1.8E-07	lb/MMBtu	3.6E-05	1.6E-04	1.2E-08	lb/MMBtu	2.3E-06	1.0E-05
Project Emissions Increase						4.7				2.2				19.0				1.6				22.9				17.3				4.2E-04				0.9				1.6E-04				1.0E-05
Duct Burner and SCR Baseline Emissions						-				-				-								-				-				-				-				-				
Project Emission Increase (Potential - Baseline)						4.7				2.2				19.0				1.6				22.9				17.3				4.25E-04				0.9				1.6E-04				1.0E-05

Assumptions:

- Maximum Heat Input Capacity = 575 MMBtu/hr *5 Boilers *96.5% availability at 3SPS
- Projected actual gas usage rates are based on assuming 8,760 hours of operation at the maximum permitted capacity.
- No credit is currently taken for NOx reductions from the boilers.
- Post -SCR NOx emissions are based on vendor guarantee emission rates using SCR technology.
- Since the duct burners are new units, PTE is used for the projected actual emissions.
- SO2 emissions are calculated using Refinery fuel gas HHV before the CXHO project and the Ideal Gas Law
- Fuel Gas Heating Value = 1203.3 BTU/scf
- Natural Gas Heating Value = 1020 BTU/scf

-Ammonium Sulfate Molecular Weight = 132.14
-Sulfur Trioxide Molecular Weight = 80.06
- Sulfur Dioxide Molecular Weight = 64.06
- Sulfuric Acid Mist Molecular Weight = 98.07
- BP is conservatively considering that all of the SO_3 emitted can form both condensable particulate matter and sulfuric acid mist.
- Fraction of SO_3 converted to Sulfuric Acid Mist = 1
- Moles in 1 MMscf (n from Ideal Gas Law) (lbmol/MMscf) 2596.15 *Derived from the Ideal Gas Law, assuming V = 1MMscf, P = 14.7 psia, T = 527.7 R, R = 10.73 psia-ft^3/lbmol-R*

Fugitive Emission Calculations for New Boilers

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	126	0.5789	0.0013	2.0%	1.6194	95%	100%	0.35
Light Liquid	0	0.1878	0.0037	2.0%	0.0000	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	76	0.0827	0.00013	0.3%	0.0287	30%	100%	0.09
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	3	3.728	0.0985	2.0%	0.5133	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	1	0.0827	0.00013	2.0%	0.0018	0%	100%	0.01
							Total VOC Emissions (tons/yr):	**0.45**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Fugitive Emission Calculations for Fuel Gas Lines for 3 SPS SCR Duct Burners

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	150	0.5789	0.0013	2.0%	1.9278	95%	100%	0.42
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	255	0.0827	0.00013	0.3%	0.0963	30%	100%	0.30
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	10	0.02635	0.0033	2.0%	0.0376	0%	100%	0.16
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.88**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500//10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

1131	Required Boiler Heat Input (MMBTU/hr)* (2 boilers at 580 MMBtu/hr each at 97.5% total annual utilization)

8760	Hours of Operation

Conservative Emissions Case

Pollutant	Emission Factor** (lb/MMBtu)	Emissions (lb/hr)	Emissions (tpy)
NOx	0.065	73.5	322.0
SO2	***	20.0	49.8
PM	0.002	2.1	9.2
PM10/PM 2.5	0.007	9.7	40.0
CO	0.024	27.1	118.9
VOC	0.005	6.1	26.7
Sulfuric Acid Mist	5.E-04	0.5	2.3
Lead	4.9.E-07	6.E-04	2.E-03
Mercury	1.8E-07	2.E-04	9.E-04
Berylllium	1.18E-08	1.E-05	6.E-05

0.065	NOx (lb/MMBtu)
0.007	PM10/PM2.5 (lb/MMBtu)
0.024	CO (lb/MMBtu)
0.005	VOC (lb/MMBtu)
3%	% Conversion of SO2 to SO3
64.06	Molecular Weight of SO2
98.07	Molecular Weight of H2SO4

** EF Notes:

1) NOx factor based on manufacturer's guarantee (control technology/technique to be determined)

2) SO2 emissions will be limited to 24.9 tpy per boiler and emissions will be calculated based on total sulfur in refinery fuel gas. Natural gas blending will be used, if necessary.

3) PM based on AP-42 Table 1.4-2.

4) PM10/PM2.5 emission factor based on AP-42 Table 1.4-2 total particulate (condensible and filterable); Note that additional PM10/PM2.5 emissions were added, assuming that an SCR may be added to the boilers and 3% conversion of SO2 emissions to SO3 and ammonium sulfate.

5) CO based on manufacturer's guarantee.

6) Refinery fuel gas heating value assumed to be 1200 BTU/scf

7) VOC based on AP-42 Section 1.4 for natural gas

8) Lead, beryllium, and mercury emissions based on AP-42 Section 1.4 for natural gas.

9) Sulfuric Acid Mist emissions based on assumed conversion percentage of SO2 to SO3 and the assumption that all SO3 converts to sulfuric acid mist.

Refinery Fuel Gas HHV (BTU/scf)	1200
Natural Gas HHV (BTU/scf)	1020
Natural Gas SO2 Emission Factor (lb/MMscf)	0.6
Refinery Fuel Gas SO2 Emission Factor (at S ppm listed above) (lb/MMscf)	0.0

3 SPS Baseline for CO Reduction

F-factor	
8710	scf/mmbtu
7.27E-08	K-factor for CO
28	CO MW

CO and O2 Analyzer Data:

	%O2		CO (ppm)		MMSCF/yr		BTU/scf		MMBTU/yr		lb/MMBTU		CO (tpy)	
	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005	**2004**	**2005**
Boiler 31	9.36	8.45	27.24	90.9	2690.84	2749.28	1150.09	1279.182	3,094,708	3,516,834	0.031248	0.096657	48.3512	169.9629
Boiler 32	6.21	9.59	24.85	20.3	3213.87	2408.26	1150.09	1279.182	3,696,238	3,080,596	0.022404	0.023803	41.40467	36.66309
Boiler 33	5.88	7.46	39.91	30.4	3173.27	2616.82	1150.09	1279.182	3,649,546	3,347,394	0.035174	0.02995	64.18397	50.12744
Boiler 34	8.96	8.17	15.77	53.5	2748.05	2703.50	1150.09	1279.182	3,160,510	3,458,261	0.017484	0.055669	27.62978	96.25842
Boiler 36	6.79	7.71	57.16	60.5	3045.04	2718.25	1150.09	1279.182	3,502,070	3,477,131	0.053638	0.060762	93.92229	105.6381
TOTAL												**TOTAL**	**275.4919**	**458.6499**

boiler	31	32	33	34	36	Total
Averages 2004-2005	**109.16**	**39.03388**	**57.15571**	**61.94410002**	**99.78019**	367.07

Notes:

- %O2, ppm CO and MMSCF/yr are annual average values obtained from averaging monthly CEMS and analyzer data
- Note that this conservatively uses CO analyzer data instead of the data reported in the TRI/I-Steps based on the emission factor.

Potential to Emit for 3 SPS Boilers Based on Vendor Guaranteed Emission Factor and Limited Utilization Factor of 96.5%

Process Unit	Maximum Heat Capacity		CO				
			EF	Unit	lb/hr	tpy	
3SPS 1	555	MMBtu/hour	0.02	lb/MMBtu	11.1	48.6	per boiler
3SPS 2	555	MMBtu/hour	0.02	lb/MMBtu	11.1	48.6	
3SPS 3	555	MMBtu/hour	0.02	lb/MMBtu	11.1	48.6	
3SPS 4	555	MMBtu/hour	0.02	lb/MMBtu	11.1	48.6	
3SPS 6	555	MMBtu/hour	0.02	lb/MMBtu	11.1	48.6	

CO Emission Factor is based on vendor guarantee.

CO Emissions Reductions from 3 SPS Boilers

Boiler	CO	
	tpy	
1	(60.5)	*Future Potential CO Emissions - Past Actual CO Emissions*
2	9.6	
3	(8.5)	
4	(13.3)	
6	(51.2)	
Total	**(124.0)**	*Total CO Reduction*

Tank 8

Tank 8 is an oil/water separator that currently handles the wastewater associated with the 11 Pipe Stills. This is a new oil/water separator system that may eventually replace Tank 8; however, both may operate for a period of time.

Estimated New Fugitive Components Associated with the Tank 8 Oil/Water Separator System

Component Type	# of components
Valves	
Gas/Vapor	15
Light Liquid	15
Heavy Liquid	50
Pumps	
Light Liquid	
Heavy Liquid	15
Flanges	
Gas/Vapor	20
Light Liquid	20
Heavy Liquid	40
Compressors	0
Relief Valves	5
Open-ended Lines	0
Sampling Connections	8

New Tank 8 Oil/Water Separator System

Maximum average daily estimated flow rate of material through the new Tank 8 oil/water separator (gal/day)	100,000	*Based on design estimates*
VOC Emission Factor (lb/kgal)	0.2	*Covered Oil/Water Separator from AP-42 Table 5.1-2 (1/95)*
VOC Emissions (lbs/day)	20	*Maximum average daily flow rate * VOC Emission Factor*
VOC Emissions (tpy)	3.7	*VOC Emissions lbs/day * 365 days /yr * 1 ton/2,000 lbs*

Note that the oil/water separator will be subject to the requirements of 40 CFR 61, Subpart FF and will be equipped with carbon canisters to control emissions.

Note that a new junction box and new manhole and sewer drain may be installed, depending on the final location chosen within the refinery.

Fugitive Emission Calculations for Tank 8 OWS Replacement

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	15	0.5789	0.0013	2.0%	0.1928	95%	100%	0.04
Light Liquid	15	0.1878	0.0037	2.0%	0.1107	95%	100%	0.02
Heavy Liquid	50	0.00051	0.00051	2.0%	0.0255	30%	100%	0.08
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	15	0.8565	0.02976	2.0%	0.6944	30%	100%	2.13
Flanges								
Gas/Vapor	20	0.0827	0.00013	0.3%	0.0076	30%	100%	0.02
Light Liquid	20	0.0827	0.00013	0.3%	0.0076	30%	100%	0.02
Heavy Liquid	40	0.0827	0.00013	0.3%	0.0151	30%	100%	0.05
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	5	3.728	0.0985	2.0%	0.8555	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	8	0.0827	0.00013	2.0%	0.0143	0%	100%	0.06
							Total VOC Emissions (tons/yr):	**2.43**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Diesel Fire Pump Engines Emissions

There are three identical diesel fire pump engines

Hours of Operation	500	*Emergency fire pump engines used for the fire water system*
Number of Engines	3	
Engine HP	390	*Actual mechanical HP estimated based on the mechanical effciency, assumed 0.9*
Load Factor	100%	*Conservatively assumes that pump engine is operated at 100% load, actual load depends on operating point of engine/pump combination*

		NO_x		CO		$PM/PM_{10}/PM_{2.5}$		SO_x		VOC
		AP-42	NSPS IIII	AP-42	NSPS IIII	AP-42	NSPS IIII	AP-42	Low Sulfur Diesel	AP-42
Emission Factor (lb/hp*hr)		0.031		0.00668		0.0022		0.00205		0.00251
Emission Factor (g/hp*hr)		14.0616	**7.8**	3.030048	**2.6**	0.99792	**0.4**	0.92988	**0.161**	1.138536
Emission Factor (g/kw*hr)		18.848	**10.5**	4.06144	**3.5**	1.3376	**0.54**	1.2464		1.52608
Emissions (lb/hr)	each engine	6.71		2.24		0.34		0.14		0.98
Emissions (tpy)	each engine	1.68		0.56		0.09		0.03		0.24
Total Emissions (lb/hr)		20.12		6.71		1.03		0.42		2.94
Total Emissions (tpy)		5.03		1.68		0.26		0.10		0.73

Notes

Emission factors are from AP-42 Section 3.3, Table 3.3-1 (10/96) and NSPS Subpart IIII.

VOC emission factor is the sum of the TOC emission factors for exhaust and crankcase.

PM is assumed to be equal to PM_{10} for the purposes of these calculations. It should be noted that AP-42 Section 3.3 does not include a PM emission factor, and footnote b of Table 3.3-1 indicates that all particulate is assumed to be less than 1 micrometer.

Emission factors noted in red are emission standards for engine 300~600 HP, per 40 CFR 60, Subpart IIII

Emission estimates are based on the lower of AP-42 emission factors and Subpart IIII emission limits

40 CFR Subpart IIII limits NOx + NMHC. NOx assumed emitted at Subpart IIII limit and VOC emitted at AP-42 factor levels.

SO2 emission factor based on NSPS limit of 500 ppm fuel sulfur content and calculations below.

Sample Calculation

NOx emissions from compressor (lb/hr) =	390 hp	7.8 g NOx / hp-hr	lb / 453.6 g	100%	3 engines		= 20.12 lb NOx/hr
SO2 emission factor calculation:	0.0005 lb S / lb diesel	7.1 lb diesel / gal diesel	gal diesel / .140 MMBtu	2 lb SO2 / lb S	7000 MMBtu / 10^6 hp-hr	453.6 g / lb	0.161g SO2/hp-hr

Conversion factors found in AP-42 Table 3.3-1 were used above to calculate engine fuel efficiency in MMBtu/hp-hr

	VOC (tons/yr)	NOx (tons/yr)	PM (tons/yr)	PM10/PM2.5 (tons/yr)	CO (tons/yr)	SO2 (tons/yr)
Dewatering Emissions	0.9	n/a	n/a	n/a	n/a	n/a
Thermal Desorption Emissions (Burners and VOC)	1.0	5.2	0.5	0.8	1.3	1.8
Fugitive Equipment Components	0.6	n/a	n/a	n/a	n/a	n/a
TOTAL	2.4	5.2	0.5	0.8	1.3	1.8
PERMITTING STATUS	**EXEMPT**	**PERMIT REQUIRED**	**EXEMPT**	**EXEMPT**	**EXEMPT**	**EXEMPT**
Permitting Thresholds:						
Part 70 Minor Source Mod	2.7	4.6	5	5	25	10
Part 70 Significant Source Mod	25	25	25	25	100	25

Refer to the application text for a description of the dewatering system.

Mass Balance Emissions Calculation

Maximum values from sludge analytical data from 2000 to 2002 documented in Hazardous Waste Combustor MACT Performance Test Plans

		DAF Float/Biosolids	API Sludge
Method 8270 (SVOCs)		mg/kg	mg/kg
Anthracene		9.9	ND
Chyrsene		16.5	ND
Naphthalene		149	47
Phenanthrene		97.7	33
Pyrene		30.95	33
	Total SVOCs	**304.05**	**113**
Method 8260 (VOC)			
Benzene		110	20
Ethylbenzene		245	48
Toluene		530	66.5
Xylenes		700	180
	Total VOC	**1585**	**314.5**

Dewatering System Capacity

Density of Water (lb/gal)		8.34
Conversion Factor (lb/g)	0.0022	
Conversion Factor (mg/g)	1000	
Conversion Factor (g/kg)	1000	
Total SVOCs (lb/lb)	0.00030405	
Total VOCs in Feed (lb/lb)	0.001585	
Potential SVOC and VOC throughput (lb/lb)	0.00188905	*Sum of SVOCs and VOCs in feed*
VOC Control Efficiency (%)	95%	*Based on 40 CFR 61, Subpart FF requirements; Note that carbon actually provides a 99.9% control efficiency if monitored for breakthrough and changed after breakthrough is detected (per carbon system vendors); however, 95% used as a conservative measure in accordance with regulatory requirements.*
Thermal Desorption System Feed Rate Capacity (tons feed/year)	22500	*Based on system design (range of 18,000 to 20,000, depending on solids percentage of feed)*
Concentration Ratio of Dewatering system	4	*Typical design solids concentration ratio of sludge processed in dewatering system (pre to post dewatering system)*
Dewatering System Feed Rate Capacity (tons feed/year)	90000	*Based on system design of thermal desorption system * concentration ratio of dewatering system (range of 18,000 to 20,000, depending on solids percentage of feed)*
Percentage of Volatile Material Processed Emitted at Dewatering (%)	10%	*Engineering estimate based on relative non-volatility of material remaining in sludges after processing steps prior to dewatering system. Note that most of the oil will be recovered in the dewatering and thermal desorption system.*
Potential Uncontrolled SVOC and VOC emissions (tpy)	17.00	
Potential Controlled SVOC and VOC emissions (tpy)	**0.85**	

Thermal Desorption System

The thermal desorption system is a closed system with the exception of vents for the processed solids system, the noncondensible stream that is vented to the system burners, and the burner emissions. Refer to the application for a detailed description.

Waste Stream Composition Estimates

Solids (% by weight from the dewatering system)	40%	*Based on conservative typical design estimates*
Water (% by weight from dewatering system)	40%	*Based on conservative typical design estimates*
Oil (% by weight from dewatering system)	20%	*Based on conservative typical design estimates*

System Capacity Information

System Oil Recovery Estimate (% by weight)	80%	*Based on conservative design estimates - 90% recovery is typically expected*
Noncondensible Portion Estimate (% by weight)	20%	*Based on conservative design estimates - 10% noncondensibles are typically expected*
System Production Capacity (dry tons solids produced/year)	9000	*Based on system design*
System Feed Rate Capacity (tons feed/year)	22500	*Based on system design (range of 18,000 to 22,500, depending on solids percentage of feed)*

Noncondensible Hydrocarbons Routed to Burner

Assumes that negligible amounts of organic material will be left in recovered solids after thermal desorption and that all the material that is not recovered is included in the noncondensibles portion. Note that the noncondensible portion will consist of hydrocarbons that do not condense at above 150 to 160 degrees F such as methanes and propanes.

Oil in Feed (tpy)	4500	*Percent by weight oil in feed * System Feed Rate Capacity*
Noncondensible Portion of Oil in Feed (tpy)	900	*Percent by weight noncondensible portion * Oil in Feed*
VOC Control Efficiency (%)	99.9%	*Based on vendor tests for other applications of the thermal desorption system*
Potential VOC Emissions (tpy)	0.9	*Noncondensible Portion of Oil in Feed * (1-VOC Control Efficiency)*

Based on the previous experience of the vendor with other waste streams that contain sulfur compounds, hydrogen sulfide in the stream from the thermal desorption unit is typically absorbed in the condensed oil and elemental sulfur typically remains in the solids. The sulfur emissions from the fuel burned in the burner typically are greater than those from the supplemental noncondensible stream.

Processed Solids System

It is presumed that negligible amounts of VOC will be emitted from the recovered solids since they have been processed through the thermal desorption system. In addition, the recovered solids system will be enclosed for the rehydration process and routed to a wet scrubber. Therefore, the controlled emissions are presumed to be neglible.

Diesel Fired Burner Emissions

The thermal desorption system is equipped with two burners that burn distillate fuel. In addition, the noncondensible vapor stream is routed through the burners for destruction of the lighter hydrocarbons that are not recovered in the oil. Note that the noncondensible portion will consist of hydrocarbons that do not condense at above 150 to 160 degrees F such as methanes anc propanes.

Distillate Firing Emissions:

Hours of Operation	8760	
Burner Rating (MMBtu/hr)	8	*Total maximum rating of two burners*
Density of Diesel Fuel (lb/gal)	7.05	
Heating Value of Fuel (Btu/lb)	19,300	*From note in AP-42 section 3.3 below table 3.3-1*
Heating Value of Fuel (Btu/gal)	137,000	*From AP-42 Appendix A, Typical parameters of various fuels*
Fuel Consumed (lb/hr)	414.51	
Fuel Consumed (gal/hr)	59	
Fuel Consumed (gal/day)	1411	*Based on maximum burner capacity; Note that 750 to 1000 gallons per day is the expected usage rate*
Fuel Sulfur %	0.05	*As required by 40 CFR 80.29(a)(1) - distillate produced by BP Whiting*

Criteria Pollutants

	NO_x	CO	SO_2	PM_{10} (Filterable)	$PM_{10}/PM_{2.5}$ (Filterable + Condensable)	VOC
AP-42 Emission Factor (lb/kgal)	20	5	7.1	2	3.3	0.2
Emissions (lb/hr)	1.18	0.29	0.42	0.12	0.19	0.01
Emissions (tpy)	5.15	1.29	1.83	0.52	0.85	0.05

Other Pollutants

	Lead	Mercury	Beryllium	Benzene*
AP-42 Emission Factor (lb/10^12 Btu)	9	3	3	2.14E-04
Emissions (lb/hr)	0.00	0.00	0.00	<0.01
Emissions (tpy)	0.00	0.00	0.00	<0.01

Notes

Emission Factors taken from AP-42 Section 1.3 tables 1.3-1, 1.3-2, 1.3-3 assuming boiler fired by No. 2 oil (9/98).
VOC emission factor is NMTOC factor from AP-42 Section 1.3-3 (9/98).
SO2 emission factor = 142 * Fuel Sulfur % (AP-42, Section 1.3, Table 1.3-1, 9/98).
PM_{10} emission factor is sum of filterable and condensable factors from Tables 1.3-1 and 1.3-2.
PM is assumed to be equal to filterable factor only for purposes of these calculations.
*Other pollutant emission factors are from Tables 1.3-9 and 1.3-10. The benzene emission factor is in lb/kgal.

The thermal desorption system will use the existing diesel tank associated with the FBI system. In addition, the thermal desorption system will use less fuel than the existing FBI system has used in the past; therefore, no increases associated with the tank are included.

Sample Calculation

NOx Emissions (lb/hr) = $\frac{8\text{ MMBtu}}{\text{hr}} \cdot \frac{1000000\text{ Btu}}{\text{MMBtu}} \cdot \frac{\text{lb}}{19300\text{ Btu}} \cdot \frac{\text{gal}}{7.05\text{ lb}} \cdot \frac{\text{kgal}}{1000\text{ gal}} \cdot \frac{20\text{ lb}}{\text{kgal}}$ = 1.18 lb/hr

Process Gas Stream Combustion Emissions:

Note that the distillate fuel use will be adjusted as the noncondensible portion provides heat input capacity such that the maximum rating of the burners will remain at 4 MMBtu/hr each. Therefore, the emissions calculated for the burners should account for all combustion emissions; however the emissions from the combustion of the vapors are calculated below for reference in determining if the emissions are higher when firing process gas in lieu of some of the diesel.

Potential VOC in Noncondensible Stream (tpy)	900	
Molar Volume (L/mol)	22.41	*Volume of 1 mole of gas, based on the ideal gas law equation at standard conditions*
SO2 Molar Weight	64.06	*lb/lb-mol or g/mol*
VOC Vapor Molar Weight (lb/lb-mole)	130	*Vapor molecular weight of distillate number 2 from TANKS 4.09d*
Conversion Factor (L/cf)	28.32	
Conversion Factor (lb/g)	0.0022	
Total VOC Routed to Burners (lb-mole/hr)	1.58	
Converted Molar Volume of gas (scf/lb-mol)	359.80	
Total Volume of Organic Vapors Combusted (MMscf/hr)	5.69E-04	*Based on the total VOC combusted per hour multiplied by the molar volume of the gas*
Total Volume of Vapors Combusted (MMscf/yr)	4.98E+00	*Based on the total VOC combusted per year multiplied by the molar volume of the gas*
Higher Heating Value of Refinery Fuel Gas (MMBtu/MMscf)	1200	*Conservatively assumes that the gas has a similar heating value to refinery fuel gas, although the heating value will vary.*
Higher Heating Value of Natural Gas (MMBtu/MMscf)	1020	*This is used to convert the natural gas emission factors per footnote a in Table 1.4-1 of AP-42 Section 1.4.*
Sulfur Concentration (ppm)	46.03	*Based on the average hydrogen sulfide content of the refinery fuel gas from 2003-2004. This conservatively assumes the same H2S concentration as refinery fuel gas; however, the H2S is not expected to be present in significant quantities in the noncondensible stream since it should be absorbed in the oil condensing phase.*

	NO_x	CO	SO_2	$PM/PM_{10}/PM_{2.5}$
Emission Factor based on Natural Gas (lb/MMscf)	100	84	see below	7.6
Burner Exhaust Emissions (lb/hr)	0.07	0.06	0.06	<0.01
Burner Exhaust Emissions (tpy)	0.29	0.25	0.28	0.02

Converted Flow Rate to Burners (MMscf/hr)	0.008	*Conservatively based on natural gas heat input and the maximum capacity of the burner*
SO2 Emission Rate (lb/hr)	0.06	
SO2 Emission Rate (tpy)	0.28	

The emissions associated with the diesel burners are higher than emissions when burning process gas; therefore, the diesel burner emissions will be used for potential emissions estimates.

Notes

Emissions factors for NO_X, CO, PM_{10} are from AP-42 Section 1.4 tables 1.4-1 and 1.4-2 (7/98) assuming combustion similar to natural gas.
PM is assumed to be equal to PM_{10} and $PM_{2.5}$ or the purposes of these calculations.
Molar volume for VOC and SO2 calculated using ideal gas law at standard temperature and pressure.

These calculations are conservative as the noncondensible stream is not likely to contain as much hydrogen sulfide as the refinery fuel gas. Note that it is presumed that the sulfur compounds in the noncondensible stream will mostly be H2S. Other reduced sulfur compounds that could be formed in the thermal desorption unit have similar boiling points to the hydrocarbons that are condensed and recovered, and these other sulfur compounds are expected to condense in the oil phase with the hydrocarbons.

Fugitive Emission Factors

Equipment/Service	EPA Refinery Average Emission Factors Kg/hr/source	EPA Refinery Average Emission Factors lbs/hr/source	EPA Refinery SCREENING Emission Factors - LEAK Kg/hr/source	EPA Refinery SCREENING Emission Factors - LEAK lbs/hr/source	EPA Refinery SCREENING Emission Factors - NO LEAK Kg/hr/source	EPA Refinery SCREENING Emission Factors - NO LEAK lbs/hr/source
Valves						
Gas/Vapor	0.0268	0.059083816	0.2626	0.5789	0.0006	0.0013
Light Liquid	0.0109	0.024030358	0.0852	0.1878	0.0017	0.0037
Heavy Liquid	0.00023	0.000507063	0.00023	0.00051	0.00023	0.00051
Pumps						
Light Liquid	0.114	0.25132668	0.437	0.963	0.012	0.0265
Heavy Liquid	0.021	0.04629702	0.3885	0.8565	0.0135	0.02976
Flanges						
Gas/Vapor	0.00025	0.00055	0.0375	0.0827	0.00006	0.00013
Light Liquid	0.00025	0.00055	0.0375	0.0827	0.00006	0.00013
Heavy Liquid	0.00025	0.00055	0.0375	0.0827	0.00006	0.00013
Compressors	0.636	1.40214	1.608	3.545	0.0894	0.1971
Relief Valves	0.16	0.35274	1.691	3.728	0.0447	0.0985
Open-ended Lines	0.0023	0.00507	0.01195	0.02635	0.0015	0.0033
Sampling Connections	0.015	0.03307	0.0375	0.0827	0.00006	0.00013

Reference:

A Factors are taken from EPA Document EPA-453/R-95-017, Nov. 1995, Table 2-2, Page 2-13.

B Factors are taken from EPA Document EPA-453/R-95-017, Nov. 1995, Table 2-6, Page 2-20.

Fugitive Emission Calculations for Dewatering and Thermal Desorption System

It is conservatively assumed that the components are in light liquid or vapor service, although the components may be in heavy liquid service.
Only the new components associated with the new portions of the sludge handling system are included here.

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	22	0.5789	0.0013	2.0%	0.2827	95%	100%	0.06
Light Liquid	20	0.1878	0.0037	2.0%	0.1476	95%	100%	0.03
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	10	0.9630	0.0265	2.0%	0.4523	80%	100%	0.40
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	48	0.0827	0.00013	0.3%	0.0181	30%	100%	0.06
Light Liquid	60	0.0827	0.00013	0.3%	0.0227	30%	100%	0.07
Heavy Liquid		0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.197	2.0%	0.0000	0%	100%	0.00
Relief Valves	10	3.728	0.099	2.0%	1.7109	100%	100%	0.00
Open-ended Lines	0	0.026	0.003	2.0%	0.0000	0%	100%	0.00
Sampling Connections	2	0.083	0.00013	2.0%	0.0036	0%	100%	0.02
							Total VOC Emissions (lbs/day):	**3.46**
							Total VOC Emissions (tons/yr):	**0.63**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500//10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Significant Source Modification and Significant Permit Modification.

Source Description and Location

Source Name:	BP Products North America Inc., Whiting Business Unit.
Source Location:	2815 Indianapolis Blvd., Whiting Indiana 46394
County:	Lake
SIC Code:	2911 and 2869
Operation Permit No.:	T 089-6741-00453
Operation Permit Issuance Date:	December 14, 2006
Significant Source Modification No.:	089-25484-00453
Significant Permit Modification No.:	089-25488-00453
Permit Reviewer:	Madhurima Moulik

Source Definition

This stationary source consists of two (2) plants, with a third plant located on an adjacent site:

(a) The Whiting Refinery (previously designated 089-00003), located at 2815 Indianapolis Boulevard, Whiting, Indiana 46394; and

(b) The Marketing Terminal (previously designated 089-00004), located at 2530 Indianapolis Boulevard, Whiting, Indiana 46394.

(c) INEOS USA LLC (designated as 089-00076), 2357 Standard Avenue, Whiting, IN 46394.

Since the two (2) plants (Whiting Refinery and the Marketing Terminal) are located on contiguous or adjacent properties, the plants are under common control of the same entity, and the Whiting Refinery supports the Marketing Terminal, the two (2) plants are considered one (1) source.

In the case of the BP Whiting refinery and the INEOS USA LLC chemical plant, neither plant has a major role in the day-to-day operations of the other plant. There is no contract between the two companies concerning the acceptance or usage of raw materials. Each plant is free to obtain raw materials from other sources. The chemical plant has obtained raw materials from other sources in the past when the refinery has been unable to supply it. Neither plant provides a majority of its output to the other plant. Neither plant has the right to assume control of the other under any circumstance. The INEOS chemical plant purchases steam, water, wastewater service and a raw material stream from the BP refinery. If the refinery were to cease operations, the chemical plant could continue to operate.

The BP refinery purchases a hydrocarbon stream from the chemical plant. It also sends by-products to the INEOS chemical plant's flare. The flared by-products come from the venting of rail cars and the depressurizing of drums. The refinery does not rely on the hydrocarbon stream in order to produce its principal products. The refinery does not rely on the INEOS flare. If the INEOS chemical plant were to cease operations, the refinery could continue to operate. The refinery has a procedure in place on what steps its employees take when the INEOS flare is unavailable. Neither plant is dependent on the other to operate.

Since there is no common control, the refinery and the chemical plant are not part of the same major source. There is no need to examine the other two criteria under the definition of major source. Therefore, the chemical plant is not included in this Title V Operating Permit. The chemical plant will receive a separate operating permit.

Existing Approvals

The source was issued Part 70 Operating Permit No. 089-6741-00453 on December 14, 2006. The source has since received the following approvals:

(a) First Minor Source Modification No. 089-23783-00453, issued on February 20, 2007;
(b) Second Minor Source Modification No. 089-24258-00453, issued on March 30, 2007;
(c) First Significant Permit Modification No. 089-24068-00453, issued on May 21, 2007; and
(d) Second Significant Permit Modification No. 089-24410-00453, issued on June 19, 2007.

County Attainment Status

The source is located in Lake County.

Pollutant	Status
PM10	Attainment
PM2.5	Nonattainment
SO_2	Attainment
NO_2	Attainment
8-hour Ozone	Moderate Nonattainment
CO	Attainment
Lead	Attainment

Note: Effective on October 25, 2006, 326 IAC 1-4-1 has been revised to revoke the one-hour ozone standard and redesignate Lake County to attainment for the Sulfur Dioxide standard.

(1) On December 22, 2006 the United States Court of Appeals, District of Columbia issued a decision that served to partially vacate and remand the U.S. EPA's final rule for implementation of the eight hour National Ambient Air quality Standard for ozone. South Coast Air Quality Mgmt. Dist. v. EPA, 472 F.3d 882 (D.C. Cir., December 22, 2006), rehearing denied 2007 U.S. App. LEXIS 13748 (D.C. Cir., June 8, 2007). The U.S. EPA has instructed IDEM to issue permits in accordance with its interpretation of the South Coast decision as follows: Lake County was previously designated as a severe non attainment area prior to revocation of the one hour ozone standard, therefore, pursuant to the anti backsliding provisions of the Clean Air Act, any new or existing source must be subject to the major source applicability cut offs and offset ratios under the area's previous one hour standard designation. This means that a source must achieve the Lowest Achievable Emission Rate (LAER) if it exceeds 25 tons per year of VOC emissions and must offset any increase in VOC emissions by a decrease of 1.3 times that amount.

On January 26, 1996 in 40 CFR 52.777(i), the U.S. EPA granted a waiver of the requirements of Section 182(f) of the CAA for Lake and Porter Counties, including the lower NO_X threshold for nonattainment new source review. Therefore, VOC emissions alone are considered when evaluating the rule applicability relating to the 1 hour ozone standards. Therefore, VOC emissions were reviewed pursuant to the requirements for nonattainment new source review.

(2) Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NOx emissions are considered when evaluating the rule applicability relating to the ozone standards. Lake County has been designated as nonattainment for the 8-hour ozone standard. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for nonattainment new source review.

(3) U.S. EPA, in the Federal Register Notice 70 FR 943 dated January 5, 2005, has designated Lake County as nonattainment for PM2.5. On March 7, 2005 the Indiana Attorney General's Office, on behalf of IDEM, filed a law suit with the Court of Appeals for the District of Columbia Circuit challenging U.S. EPA's designation of nonattainment areas without sufficient data. However, in order to ensure that sources are not potentially liable for a violation of the Clean Air Act, the OAQ is following the U.S. EPA's guidance to regulate PM10 emissions as a surrogate for PM2.5 emissions pursuant to the requirements of Emission Offset, 326 IAC 2-3.

(4) Lake County has been classified as attainment or unclassifiable for PM_{10}, SO_2, NO_2, CO, and lead. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(5) Fugitive Emissions
Since this type of operation is in one of the twenty-eight (28) listed source categories under 326 IAC 2-2, the fugitive PM and VOC emissions are counted toward determination of PSD and Emission Offset applicability.

Source Status

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

Pollutant	Emissions (tons/year)
PM	>100
PM_{10}	>100
SO_2	>100
VOC	>100
CO	>100
NO_x	>100

(1) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a regulated pollutant is emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(gg)(1).

(2) This existing source is a major stationary source under Emission Offset (326 IAC 2-3) and Nonattainment NSR (326 IAC 2-1.1-5) because the nonattainment regulated pollutants PM10 (as surrogate for $PM_{2.5}$), VOC and NO_x are emitted at a rate of 100 tons per year or more.

(3) These emissions are based upon the 2003 emissions data submitted to IDEM, OAQ.

The table below summarizes the potential to emit HAPs for the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

HAPs	Potential To Emit (tons/year)
Single HAPs	>10
TOTAL HAPs	>25

This existing source is a major source of HAPs, as defined in 40 CFR 63.41, because HAP emissions are greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

Actual Emissions

The following table shows the actual emissions from the source. This information reflects the 2003 OAQ emission data.

Pollutant	Actual Emissions (tons/year)
PM	-
PM_{10}	557
SO_2	3,385
VOC	1,274
CO	2,058
NO_x	7,637
HAP (Lead)	0.03*

***** No data provided for other HAPs. Source stated in their application that they are a major source of HAPs.

Description of New and Modified Emission Units and Units Scheduled for Shutdown as Part of CXHO

On November 1, 2007, the Office of Air Quality (OAQ) received an application from BP Products North America Inc., Whiting Business Unit to modify their refinery, located at 2815 Indianapolis Blvd, Whiting, Indiana, in Lake County. The modifications at the plant are being performed to accommodate additional processing of Canadian Extra Heavy Crude Oil (CXHO), and will be referred to as the CXHO Project (also known as the Operation Canadian Crude [OCC] project). The following are the new and the modified emission units (including shutdown of units as part of CXHO project), and new control devices for existing emissions units.

(a) New Coker (#2 Coker), which processes heavy crude fractions into coke, and new Coke Handling System. These facilities are identified as Unit 800 and are rated at 6,000 tons of coke per day. The New Coker heaters H-201, H-202, and H-203 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New Coker (#2 Coker) heater stacks have continuous emissions monitors (CEMS) for NOx and CO. The No. 11B Coker and Coke Pile, heaters H-101, H-102, H-103, and H-104 will be replaced by the New Coker (#2 Coker) and Coke Handling System and heaters H-201, H-202, and H-203 as part of the CXHO project. The facility includes the following emission sources and may include insignificant activities:

(1) Process heaters comprising of:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted to	Emission Controls
H-201	208	800-01	Low-NO_X burners and selective catalytic reduction
H-202	208	800-02	Low-NO_X burners and selective catalytic reduction
H-203	208	800-03	Low-NO_X burners and selective catalytic reduction

(2) Storage and handling (including up to 10 transfer points) of the bulk material comprised of a partially enclosed crusher, enclosed conveyors, enclosed storage, day bins, and rail car load out under the main operating scenario. In order to minimize fugitive emissions from the coke handling process, transfer points 1 and 10 will include enclosed conveyors and transfer points 2 through 9 will use enclosed buildings, and water sprays. Coke handling operations will be expected to operate under this main operating scenario for at least 95% of operating hours annually.

There will also be an alternative operating scenario, which will consist of three enclosed conveyors with unenclosed transfer points. Coke handling operations are expected to operate under this alternate operating scenario for no more than 5% of operating hours annually.

(3) The Coker is connected to the South flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) One (1) storage tank, identified as TK-6255, with a maximum storage capacity of 14,028,000 gallons storing coker resid at a vapor pressure less than 0.5 psia. Tank TK-6255 is equipped with a fixed roof.

(5) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(b) The Gas Oil Hydrotreater (GOHT) Unit, identified as Unit ID 802 and rated at 120,000 barrels per day. The GOHT reduces the sulfur and nitrogen content of the FCU feed and improves the hydrogen content. Operation of the GOHT will enable the FCU to meet gasoline sulfur specifications and to improve FCU conversion yields. The GOHT Unit will be constructed as part of the CXHO Project and includes the following emission units:

(1) Process heaters comprising of:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-901A	47	802-01	Ultra low-NO_X burners
F-901B	47	802-02	Ultra low-NO_X burners

(2) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(3) The GOHT Unit vents to the GOHT Flare, used to control VOC emissions during emergency situations, unit startups and shutdowns.

(c) The New Hydrogen (New HU), identified as Unit ID 801 commissioned as part of the CXHO Project, produces 99+% pure hydrogen needed for the refinery hydrotreating processes. The New HU produces high purity hydrogen by reacting steam with methane. The New HU heaters HU-1 and HU-2 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New HU heater stacks have continuous emissions monitors (CEMS) for NOx and CO. The New HU includes the following sources of emissions and may include insignificant activities listed in Section A.4 of this permit:

(1) Process heaters comprising of:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted to	Emission Controls
HU-1	920*	801-01	Low-NO_X burners and selective catalytic reduction
HU-2	920*	801-02	Low-NO_X burners and selective catalytic reduction

* HU Heaters HU-1 and HU-2 combust both natural gas and PSA tail gas with a fuel ratio of no more than 25% natural gas and the remainder PSA tail gas.

(2) One cooling tower (HU Cooling Tower) rated at 14,000 gallons per minute recirculation rate controlled by high efficiency drift eliminators.

(3) The new Hydrogen Unit is connected to the HU Flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The HU Flare will be operated with a water seal or nitrogen purge. As such, there will be no purge gas emissions from the HU Flare. The HU Flare exhausts to S/V 801-03.

(4) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(d) New 12 Pipe Still Heaters - Three (3) new heaters:

Heater Identification	Permitted Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-101A	Permitted in 2008	355	130-05	Ultra low NOx Burners
H-101B	Permitted in 2008	355	130-07	Ultra low NOx Burners
H-102	Permitted in 2008	331	130-06	Ultra low NOx Burners

The No. 12 Pipe Still Heaters identified as H-1AN, H-1AS, H-1B, H-2, H-1CN, H-1CS, and H-1CX will be shutdown and replaced by heaters H-101A, H-101B, and H-102 as part of the CXHO project.

(e) Nos. 11A and 11C Pipe Stills

(1) Ultra low-NOx burners will be installed on the 11C PipeStill (11CPS) heater identified as H-200.

(2) One (1) redundant oil water separation system (identified as Tank 8a), permitted in 2008, with a maximum storage capacity of 124,800 gallons, equipped with a carbon canister for VOC control.

(3) As part of the No. 11A PS and No. 11C PS WARP, permitted in 2008, the two existing blowdown stacks identified as stacks 11PS-A and 11PS-C will be shutdown, with the emergency pressure relief discharge that was previously routed to the blowdown stacks being re-routed to the DDU flare, except for T-300 vacuum tower relief discharge and the COV's.

(f) New Distillate Hydrotreating Unit Heater

Replacement DHT Unit Heater B-601A, to be constructed as part of CXHO project. As part of the CXHO Project, DHT Unit Heater B-601 will be replaced with a 41.9 MMBtu per hour natural gas fired heater, identified as B-601A. NOx emissions are controlled by ultra low NOx burners having an emission rate of 0.04 pounds per million Btu heat input or less. Emissions are exhausted to a stack identified as 720-01.

(g) Sulfur Recovery Unit Complex

(1) Two (2) Claus Offgas Treaters (COT), identified as COT1 and COT2 to be installed as part of the CXHO project, thermal oxidation systems which combust natural gas, each rated at 72 mmBTU/hr, exhausting at stacks S/V 162-06 and 162-07.

(2) Two (2) sulfur storage tanks, identified as SH-1 and SH-2, each with a maximum storage capacity of 1,008,000 gallons and used to store molten sulfur exhausting to stacks S/V 163-09 and 162-10. These tanks will be constructed as part of the CXHO Project and are both fixed roof tanks controlled by a caustic scrubber.

(3) Two (2) modular degassing units, to be installed as part of the CXHO project, which remove gases that are emitted during the cooling of molten sulfur. The gases will be vented to the front-end of Claus Trains D and/or E as part of the CXHO project.

(4) Two (2) sulfur pits (Sulfur Pits D and E), to be installed as part of the CXHO project, used to store molten sulfur and the vents routed to either COT 1 and/or COT 2.

(5) The B/S TGU, SBS TGU, SRU Standby Incinerator and SBS cooling tower will be decommissioned as part of the CXHO project.

(h) Wastewater Treatment Plant (WWTP), identified as Unit ID 544:

(1) One (1) storage tank (identified as Tank 5052) having a maximum storage capacity of 11,676,000 gallons, to be constructed as part of the CXHO Project. This tank will be used as a stormwater equalization tank and is equipped with an external floating roof.

(2) A brine treatment system with seven (7) wastewater tanks with vertical fixed roofs, constructed as part of CXHO project, identified as:

(A) TK-105A, with a storage capacity of 867,180 gallons;
(B) TK-105B, with a storage capacity of 867,180 gallons;
(C) TK-101, with a storage capacity of 66,096 gallons;
(D) TK-102, with a storage capacity of 66,096 gallons;
(E) TK-103, with a storage capacity of 66,096 gallons;
(F) TK-104A, with a storage capacity of 89,943 gallons; and
(G) TK-104B, with a storage capacity of 89,943 gallons.

(i) Oil Movements, identified as Unit 640: Miscellaneous changes to storage tanks as follows:

(1) The following new and replacement tanks:

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	Vapor Pressure of Liquid (psia)
3637	Oil Movements	Petroleum hydrocarbons	1956, to be reconstructed in 2008	6,353,000	< 15.0
BT-002	Marine Dock	Wastewater containing hydrocarbons	1968 (pre-CXHO - out of operation) reconstructed in 2008	874,944	---

(j) Cooling Towers with controls installed as part of the CXHO project:

Cooling Tower	Recirculation Rate/Make-up rate (gallons/minute)	Control Devices
Cooling Tower 2*	50,000/1,285	high efficiency liquid drift eliminators
Cooling Tower 3	90,000/1,571	high efficiency liquid drift eliminators
Cooling Tower 4	44,000/1,085	high efficiency liquid drift eliminators

* Half of the Cooling Tower 2 modules were controlled prior to the CXHO Project. Contemporaneous to the CXHO Project the other modules will be controlled with high efficiency drift eliminators.

Cooling Towers installed as part of the CXHO project:

Cooling Tower	Recirculation Rate/Make-up rate (gallons/minute)	Control Devices
Cooling Tower 7	21,000/451	high efficiency liquid drift eliminators
Cooling Tower 8	90,000/2,956	high efficiency liquid drift eliminators

(k) The Isomerization Unit (ISOM), identified as Unit ID 210, was constructed in 1985 as a conversion of the No.2 Ultraformer. The Isomerization process converts low octane naphtha into high octane gasoline blending components. This unit is connected to flare stack S/V 220-04, the UIU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the CXHO project, the ISOM heater H-1 will be modified by replacing several burners with larger burners, with rated capacity remaining at 190 MMBTU/hr. The facility includes the following emission sources and may include insignificant activities:

(1) One (1) natural gas, refinery gas, or liquefied petroleum gas-fired Process Heater H-1, modified as part of CXHO, rated at 190 MMBtu/hr and vented to stack S/V 210-01.

(l) A vapor recover unit to be installed on the Marine Dock Loading Operation to control gasoline loading emissions. The vapor recovery unit will control gasoline loading operations to 10 mg of VOC emissions per liter of product.

(m) The No.3 Ultraformer Unit (No. 3 UF), identified as Unit ID 220, commissioned in 1958. The majority of the unit was shutdown in March 2007, including the H-1, H-2 and F-7 heaters, catalyst-filled reactors and the internal scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation steps of the regeneration process. The unit consists of the C-2 Splitter Tower, the D-18 flare gas separator, D-24 knock-out drum and associated piping. The No. 3 Ultraformer is connected to flare stack S/V 220-04, the UIU flare, to control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance and reactor regenerations. The No.3 Ultraformer includes the following sources of emissions and may include insignificant activities listed in Section A.4 of this permit.

(n) Additional hydrotreating of feed and use of sulfur reducing catalysts will be used to achieve an SO2 emissions limit of 37 ppm (at 0% oxygen) at the outlet of FCU 600.

(o) New flares used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

The flares are identified as follows:

Flare	Stack ID.	Date of Installation	Dimensions	Process Units Normally Controlled by the Flare System	Maximum Capacity (MMBtu/hr)	Pilot Fuel Type
GOHT Flare	802-03	Installed as Part of CXHO	H = 316 ft. D = 3.5 ft	GOHT	TBD	Fuel Gas and Natural Gas
South Flare	800-04	Installed as Part of CXHO	H = 350 ft. D = 5 ft	New Coker, 12PS	TBD	Fuel Gas and Natural Gas

(p) Two (2) new boilers, identified as New Boiler 1 and New Boiler 2, permitted in 2008, each rated at 580 million BTU per hour, equipped with low-NOx burners and/or Selective Catalytic Reduction (SCR) for control of NOx.

(q) As part of the CXHO Project, a vapor recovery system will be installed on the Marine Dock Loading operations to control emissions from gasoline loading.

(r) No. 3 Stanolind Power Station (3 SPS): The low NOx burners, induced flue gas recirculation (IFGR) system, and over fired air (OFA) system will be replaced by conventional burners and Selective Catalytic Reduction (SCR) on Boilers # 1, 2, 3, 4, and 6.

(s) Five (5) direct fired duct burners, constructed as part of CXHO project, rated at 41 mmBTU/hr each, equipped with low NOx burners and controlled by a SCR, to preheat the exhaust from the No. 3SPS boilers before being routed to the SCR.

(t) As part of CXHO, LDAR monitoring will be applied for pumps in heavy liquid service throughout the refinery to reduce fugitive VOC emissions.

(u) The Fluidized Bed Incinerator will be shut down, and replaced by a dewatering and thermal desorption system for processing sludge, permitted in 2008 including dissolved air flotation skimmimgs (DAF) and API oil/water separator sludge. The dewatering system will be equipped with a wet scrubber and carbon canister system and the thermal desorption unit will be equipped with a vapor recovery system to optimize absorption of hydrocarbons. The feed rate capacities at the dewatering system and thermal desorption systems are 22,500 tons of feed per year and 9,000 dry tons of solids per year, respectively. This facility includes the following emission sources and may include insignificant activities listed in Section A.4 of the permit:

(1) Two (2) centrifuges;

(2) Two (2) sludge surge tanks;

(3) One (1) oil/water mixture surge tank;

(4) One (1) enclosed auger transfer system;

(5) One (1) vapor recovery system including: an oil condensing/scrubbing system, a water condensing/scrubbing system, and an oil water separator. Uncondensed vapors from this system are routed to the two (2) diesel fired burners for destruction of VOCs.

Insignificant Activities:

(a) Three (3) emergency firepump engines, identified as Firepump 1, 2 and 3, permitted in 2008, each rated at 390 HP.

(b) One (1) concrete crushing process, permitted in 2008, with a maximum processing capacity of 120 tons per hour, having two (2) transfer points.

(c) As part of the VRU 100/200 Whiting Atmospheric Relief Project (WARP), permitted in 2008, the pressure relief discharges that vented to the existing VRU 100/200 vent stack are being re-routed to the VRU flare.

(d) VRU 100/200 turnaround (TAR) project, permitted in 2008, for the repair or replacement of tower trays, and increasing existing pumping and cooling capacities, with no associated increase in emissions of any regulated pollutants.

(e) As part of the FCU 500 WARP, permitted in 2008, the FCU 500 blowdown stack will be shutdown and the pressure relief discharges that vent to the blowdown stack will be re-routed to the VRU flare.

(f) The FCU 500 turnaround (TAR) project, permitted in 2008, for the repair or replacement of the power recovery turbine, and the air ring for the catalyst regenerator. The increases in emissions from FCU 500 TAR are already accounted for as CXHO project related emissions increases.

(g) As part of the FCU 600 WARP, permitted in 2008, to shutdown the existing FCU 600 blowdown stack and the pressure relief discharges that were vented to the blowdown stack will be re-routed to the FCU flare. As part of the FCU 600 WARP, permitted in 2008, the FCU 600 blowdown stack will be shutdown and the pressure relief discharges that vent to the blowdown stack will be re-routed to the VRU flare.

(h) The FCU 600 turnaround (TAR) project, permitted in 2008, for the repair or replacement of the main fractionator overhead condensers, the slurry and pump around system, unit pump replacement, FCU flare tip replacement, addition of a soot blower, and additional controls to reduce plugging on the SCR. The increases in emissions from FCU 600 TAR are already accounted for as CXHO project related emissions increases.

(i) Two (2) diesel fired burners rated at 4 mmBTU/hr each, for the thermal desorption system.

(j) Vapor Recovery Unit VRU 400, for the New Coker.

Enforcement Issues

IDEM is aware that on November 29, 2007, U. S. EPA issued a Notice of Violation to BP Products North America, Inc., for alleged violations of Clean Air Act requirements for its Whiting refinery. Some of the units specified in the Notice of Violation are affected units in the CXHO project. The U. S. EPA is reviewing this matter and will take appropriate actions.

Emission Calculations

The Permittee has submitted emissions calculations for new units, modified units, and affected units that are included in the CXHO project. IDEM, OAQ has verified this information. See Appendix A of this document for detailed emissions calculations.

Permit Level Determination – Part 70

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as “the maximum capacity of a stationary source or emission unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, IDEM, or the appropriate local air pollution control agency.”

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

Pollutant	PTE New Emission Units (tons/year)*	Net Increase to PTE of Modified Emission Units (tons/year)**	Total PTE for New and Modified Units (tons/year)
PM	78.8	-	78.8
PM10	125.8	-	125.8
SO_2	281.7	-	281.7

Pollutant	PTE New Emission Units (tons/year)*	Net Increase to PTE of Modified Emission Units (tons/year)**	Total PTE for New and Modified Units (tons/year)
VOC	202.5	-	202.5
CO	367.4	-	367.4
NO_X	464.4	-	464.4

* This includes increases in fugitive VOC emissions from the increases in the number of valves, pumps, flanges, compressors, relief valves, open-ended lines, and sampling connections (source-wide), fugitive PM and PM-10 emissions from New Coker, and fugitive CO emissions from New HU.

** There is no increase in the potential to emit of pollutants from modified heaters 3UF H-1, BOU heater F-401, and ISOM heater H-1.

This source modification is subject to 326 IAC 2-7-10.5(f)(4)(D), because it is a modification with potential to emit greater than twenty-five (25) tons per year of PM, PM10, SO2, VOC, CO and NOx. Additionally, the modification will be incorporated into the Part 70 Operating Permit through a significant permit modification issued pursuant to 326 IAC 2-7-12(d)(1) because it cannot qualify as minor permit modification pursuant to 326 IAC 2-7-12(b)(1)(C)(ii) or as administrative amendment under 326 IAC 2-7-11 due to the significant changes in compliance determination and monitoring requirements.

Permit Level Determination – PSD or Emission Offset

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of this Part 70 source modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

	Potential to Emit (tons/year)[3]						
	PM	PM10[5]	SO_2	VOC[6]	CO	NO_X	Pb
Project Emissions Increase	138.9	216.7	277.7	225.6	541.8	456.7	0.041
Net Emissions Increase (NEI) with Past Contemporaneous Increases and Decreases	-17.5	60.5	(see footnote) ***	239.0	602.2	538.5	-0.02
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases related to CXHO (phased construction) [1, 4]	-204.2	-5.0	(see footnote) ***	163.9	351.6	18.7	-0.02
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases – non-CXHO (phased shutdown) [1]	-281.9	-1.6	(see footnote) ***	-6.3	-23.7	-28.9	-0.02
Total for Modification after Netting[2]	-281.9	-41.6	(see footnote) ***	-6.3	-23.7	-28.9	-0.02
Significant Level or Major Source Threshold	25	15	40	25	100	40	0.6

[1] The details of the phased construction of new emissions units, installation of control devices on existing emissions units, and scheduled shutdown of existing emissions units are included in Appendix A of this Technical Support Document. Net emissions decreases are shown within brackets ().

[2] The details of the net emissions increases and decreases are included in Appendix A of this Technical Support Document, Table C.82, C.82a and C.83.

[3] Methodology for limited PTE calculations:
For new, modified, and existing process heaters, after scheduled phased shutdown of emissions units or reduction in emissions have occurred:

Potential to Emit (limited) in tons per 12 consecutive month period = Limited fuel usage (mmBtu per 12 consecutive month period) x emission factor (lb/mmBtu)

[4]In addition to scheduled shutdown of existing emissions units, the following reductions in emissions are scheduled as part of the CXHO project:

(A) The firing rates at the following existing affected heaters (unmodified) will be limited in future as part of the CXHO project:

Facility	Heaters:
11A PS and 11C PS:	H-1X, H-2, H-3, H-200, H-300
4UF:	F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, F-8B
ARU:	F-200A, F-200B
BOU:	F-401
CFHU:	F-801A, F-801B, F-801C
CRU:	F-101, F-102

Facility	Heaters
DDU:	WB-301, WB-302
HU:	B-501

(B) A vapor recovery unit/vapor condensation unit will be installed at the marine loading dock, reducing VOC emissions during gasoline loading operations.

(C) Additional hydrotreating of feed and use of sulfur reducing catalysts will be used to achieve an SO2 emissions limit of 37 ppm (at 0% oxygen) at the outlet of FCU 600

(D) Low-NOx and ultra low-NOX burners will be installed on some existing heaters.

(E) High efficiency liquid drift eliminators will be installed on Cooling Towers 3,4 and half of the modules on Cooling Tower 2.

[5] Commissioner's Order No. 2007-01 has been issued with revised limits for several affected units. However, for affected units that have baseline PM-10 emissions greater than the allowable PM-10 SIP limits under 326 IAC 6.8-2-6, the baseline emissions have been adjusted to the SIP limits for estimating the PM-10 emissions increases for these affected units. The Emission Offset minor limits (PM2.5, with PM-10 as surrogate) for these affected units have been set at 0.0075 pounds per million cubic feet of fuel gas burned.

[6]VOC netting analysis performed per 326 IAC 2-3 for VOC emissions evaluation based on the NSR program effective under the 8-hour ozone standard. Pursuant to South Coast Air Quality Mgmt. Dist. v. EPA, 472 F.3d 882 (D.C. Cir., December 22, 2006), the VOC de minimis threshold of 25 tons per year has been used for applicability determination of emission offset rules as follows:

VOC Project Emissions Increase (tpy)	225.6
Net Emissions Increase (NEI) with Past Contemporaneous Increases and Decreases	-14.8
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases related to CXHO (phased construction) [1, 4]	-
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases – non-CXHO (phased shutdown) [1]	-14.8
Total for Modification after Netting[2]	-14.8
VOC De Minimis threshold	25

*** Pursuant to Consent Decree (United States et. al. vs. BP Exploration and Oil, et. al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL), 10% of SO2 netting credits generated by the cessation of oil burning at heaters and boilers and reduction of SO2 concentration at the outlet of FCU600 can be used to offset emissions increases only at units that meet the definition of "Lower Sulfur Fuel Units" and "Netting Offset Generating Units". These SO2 credits cannot be used to offset increases at other emission units, including flares and Tail Gas Units (COT1 and COT2). Table C.82a shows the detailed calculations for SO2 netting analysis conducted in accordance with the requirements of the Consent Decree. The summary of the SO2 netting analysis is as follows:

Total increases in SO2 emissions at "Low Sulfur Fuel Units" = 107.3 tpy
Total available SO2 credits from cessation of fuel oil burning = 269.4 tpy

Total increases in SO2 emissions at other "Netting/Offset Generating Units" = 149.5 tpy
Total available SO2 credits from FCU 600 consent decree reduction = 160.9 tpy

Total increases in SO2 emissions from other emission units = 203.3 tpy
Total available non-consent decree related SO2 credits = 230.1 tpy

The total available SO2 credits available as offsets in all three categories exceed the SO2 emissions increases from new, modified, affected, and future contemporaneous non-CXHO related units. Therefore, the SO2 emissions increases do not exceed the significant level for SO2.

Potential to Emit of Other Regulated Pollutants (tons/year)					
	H2SO4 Mist	**Be[A]**	**H2S**	**Total Reduced Sulfur**	**Hg[A]**
Project Emissions Increase	12.7	-0.0006	14.8	14.8	0.002
Net Emissions Increase (NEI) with Past Contemporaneous Increases and Decreases	-110.0	-0.005	-5.3	-5.3	0.001
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases related to CXHO (phased construction) [1, 4]	-113.9	0.005	-15.9	-76.1	0.0005
Net Emissions Increase/(Decrease) (NEI) with future Contemporaneous Decreases – non-CXHO (phased shutdown) [1]	-112.7	-0.005	-15.9	-76.1	-0.001
Total for Modification after Netting[2]	-112.7	-0.005	-15.9	-76.1	-0.001
Significant Level or Major Source Threshold	7.0	0.0004	10.0	10.0	0.1

[A] Not a PSD regulated Pollutant

(a) This modification to an existing major stationary source is minor because the net emissions increases for all regulated pollutants are less than the PSD significant levels. Therefore, pursuant to 326 IAC 2-2, PSD requirements do not apply.

(b) Lake County has been designated as nonattainment for PM2.5 in 70 FR 943 dated January 5, 2005. According to the April 5, 2005 EPA memo titled "Implementation of New Source Review Requirements in PM2.5 Nonattainment Areas" authored by Steve Page, Director of OAQPS, until EPA promulgates the PM2.5 major NSR regulations, states should assume that a major stationary source's PM10 emissions represent PM2.5 emissions. IDEM will use the PM10 nonattainment major NSR program as a surrogate to address the requirements of nonattainment major NSR for the PM2.5 NAAQS. A significant emissions increase would be a net emissions increase or the potential of fifteen (15) tons per year or greater of PM10. BP Products North America, Inc. – Whiting Business Unit has limited the potential to emit of PM10 from the modification to less than fifteen (15) tons per year. Therefore, assuming that PM10 emissions represent PM2.5 emissions, 326 IAC 2-1.1-5 does not apply for PM2.5.

(c) Pursuant to the South Coast Air Quality Mgmt. Dist. v. EPA, 472 F.3d 882 (D.C. Cir., December 22, 2006) decision, any new or existing source must be subject to the major source applicability cut offs and offset ratios under the area's previous one hour standard designation for VOCs. This modification to an existing major stationary source is minor because the net emissions increases for VOCs are less than significant levels under the de minimis evaluation as included in Appendix C, Table C.83. Therefore, pursuant to 326 IAC 2-3, Emission Offset requirements do not apply.

Federal Rule Applicability Determination

The following federal rules are applicable to the following new and modified emission units:

New and Replacement Storage Tanks:

(Note: The applicabilities of the NESHAPs, NSPSs and state rules to storage tanks at refineries are based on the tank storage capacities, and the vapor pressures of the liquids stored in the tanks. The following table summarizes these parameters for the new and modified tanks involved in the CXHO project):

Tank ID	Storage Capacity (m3)	Storage Capacity (gallons)	Vapor Pressure (psi)	Vapor Pressure (KPa)
TK-3637 (to be reconstructed)	23,982	6,353,000	<15.0	
BT-002 (to be modified)	3303	874,944	<15.0	
TK-6255 (new)	52,957	14,028,000	<0.5	<3.5
TK SH-1 (new)	Stores liquid sulfur only	-	-	NA
TK SH-2 (new)	Stores liquid sulfur only	-	-	NA
TK 5052 (new)	44,077	11,676,000	<0.5	<3.5
TK-101 (new)	250	66,096	0.5 RVP	<3.5
TK-102 (new)	250	66,096	0.5 RVP	<3.5
TK-103 (new)	250	66,096	0.5 RVP	<3.5
TK-104A (new)	340	89,943	0.5 RVP	<3.5
TK-104B (new)	340	89,943	0.5 RVP	<3.5
TK-105A (new)	3,282	867,180	0.5 RVP	<3.5
TK-105B (new)	3,282	867,180	0.5 RVP	<3.5

(a) The refinery is subject to 40 CFR Part 63, Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries because this plant is a major source of hazardous air pollutants (HAPs) and is a petroleum refinery.

The storage tanks TK-6255 and TK-3637 are all located at a petroleum refinery and are associated with a petroleum refining process unit. All of these tanks meet the definition of Group 2 storage vessels at an existing refinery. Therefore, these tanks are subject to the requirements of 40 CFR 63.646 (Storage Vessel Provisions) of 40 CFR 63, Subpart CC. However, pursuant to 40 CFR 63.640(n)(1), storage tanks which are also subject to the provisions of 40 CFR 60, Subpart Kb, are required to comply only with the requirements of 40 CFR 60, Subpart Kb, except as provided in 40 CFR 63.640(n)(8).

(1) The storage tank TK-6255 is not subject to 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, since the vapor pressures of the liquids stored in this tank is less than 3.5 KPa. In addition, there is no control requirements for this tank under 40 CFR 63.646 (Storage Vessel Provisions), since this tank is classified as a Group 2 storage tank. This tank shall be subject only to the reporting and recordkeeping requirements under 40 CFR 63.640(l)(1) through (l)(3).

(3) The proposed modification to Tank 3637 meets the definition of reconstruction under 40 CFR60.15(b), and therefore this tank shall be subject to the requirements under 40 CFR 60, Subpart Kb. The requirements under this subpart are included in Section E.9 of the permit. The Permittee shall also demonstrate compliance with 40 CFR 63, Subpart CC, through compliance with 40 CFR 60, Subpart Kb.

(4) The storage tank TK-5052 and the seven (7) tanks in the new brine wastewater treatment facility are wastewater tanks that meets the definition of a Group 1 wastewater stream, and is subject to 40 CFR 63.647 (Wastewater Provisions) under 40 CFR 63, Subpart CC. Pursuant to 40 CFR 63.647, tank 5052 is required to comply with the requirements of 40 CFR 61.340 through 61.355 of 40 CFR 61, Subpart FF.

(b) The two new sulfur storage tanks, TK-SH-1 and TK-SH-2 are used to store only molten sulfur and do not store any HAPs or VOCs. Therefore, these tanks are not subject to 40 CFR 63, Subpart CC or 40 CFR 60, Subpart Kb.

(c) The storage tanks TK-6255, TK-5052 (used as a stormwater equalization tank), the seven (7) tanks in the new brine wastewater treatment facility and distribution facilities at this source are not subject to 40 CFR 63, Subpart EEEE - National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline), because pursuant to 40 CFR 63.2406, organic liquids for purposes of this subpart do not include the following liquids:

(i) Gasoline (including aviation gasoline), kerosene (No. 1 distillate oil), diesel (No. 2 distillate oil), asphalt, and heavier distillate oils and fuel oils;
(ii) Any fuel consumed or dispensed on the plant site directly to users (such as fuels for fleet refueling or for refueling marine vessels that support the operation of the plant);
(iii) Hazardous waste;
(iv) Wastewater;
(v) Ballast water.

(d) Pursuant to 40 CFR 63.2338(b), storage tank D-424 (which stores organic liquids) and any equipment at this source that meets the definition of an affected source under 40 CFR 63.2334 shall comply with the requirements of 40 CFR 63, Subpart EEEE.

Oil Water Separation Systems

Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ. The proposed new oil water separation system (Tank 8a) is subject to the requirements under 40 CFR 60, Subpart QQQ.

Existing, New and Modified Boilers and Heaters

(a) The new and modified heaters H-201 (new), H-202 (new), H-203 (new), F-901A (new), F-901B (new), HU-1 (new), HU-2 (new), H-101A (new), H-101B, (new), H-102 (new), F-401 (modified), and ISOM Heater H-1 (modified) are subject to 40 CFR 60, Subpart J – Standards of Performance for Petroleum Refineries, since these are fuel gas combustion devices at a petroleum refinery. These requirements are included in section E.2 of the permit.

The new DHT heater B-601a is natural gas-fired only, and is not a fuel gas combustion device. Therefore, B-601a is not subject to the requirements of 40 CFR 60, Subpart J.

(b) Existing boilers and process heaters BP Products North America, Inc. – Whiting Business Unit were subject to the requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR Part 63, Subpart DDDDD (Industrial, Commercial, and Institutional Boilers and Process Heaters). The new heaters H-201 (new), H-202 (new), H-203 (new), F-901A (new), F-901B (new), HU-1 (new), HU-2 (new), H-101A (new), H-101B, H-102 (new) and B-601a (new) would have been subject to 40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial Commercial, and Institutional Boilers and Process Heaters, since these units are all classified as process heaters which fall under the large gaseous fuel subcategory. However, on July 30, 2007, 40 CFR Part 63, Subpart DDDDD has been vacated in its entirety.

New and Modified Process Units: Coker, GOHT, HU, No. 3 UF

(a) The emission units located at the refinery are subject to the requirements of 40 CFR 63.648 (Equipment Leak Standards) and must comply with the requirements of 40 CFR 60, Subpart GGGa. Pursuant to 40 CFR 60, Subpart GGG, the Permittee shall comply with the requirements specified in 40 CFR 60, Subpart VVa, The following new and modified emission units are subject to this rule: the new Coker, identified as Unit 800, the Gas Oil Hydrotreater Unit (GOHT), identified as Unit 802, the new Hydrogen Unit (New HU), identified as Unit ID 801. The requirements of 40 CFR 60, Subpart VVa are included in Section E.26 of the permit.

(b) The following new and modified emission units, New Coker, identified as Unit 800, the Gas Oil Hydrotreater Unit (GOHT), identified as Unit 802, the new Hydrogen Unit (New HU), identified as Unit ID 801 are subject to the requirements of 40 CFR 60 Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries (326 IAC 12) pursuant to 40 CFR60.590. Pursuant to 40 CFR 60, Subpart GGGa, these units must be operated in compliance with 40 CFR 60, Subpart VVa. The applicable requirements for 40 CFR 60, Subpart VVa are included in Section E.26 of the draft permit.

(c) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 (40 CFR 63, Subpart CC) and E.4 (40 CFR 60, Subpart VVa) for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems located at the new and modified process units, the new Coker, GOHT, and New HU.

(d) The new coker, GOHT,and HU, are not subject to 40 CFR 63, Subpart UUU - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, since none of these units are involved in processes regulated by this NESHAP.

Modified Sulfur Recovery Unit – Unit ID 162 (including COT1 and COT2 Offgas Treaters)

(a) The Sulfur Recovery Unit (SRU), is subject to the New Source Performance Standard, 40 CFR 60, Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries (326 IAC 12) because this unit will be modified as part of the CXHO project after January 4, 1983.

(b) The Sulfur Recovery Unit (SRU) is subject to the New Source Performance Standard, 40 CFR 60, Subpart J, since it is a sulfur recovery plant that has been constructed and will be modified after October 4, 1976.

(c) The Sulfur Recovery Unit (SRU) is subject to 40 CFR 63, Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. Therefore, the offgas treaters identified as COT1 and COT2 are subject to 40 CFR 63, Subpart UUU.

(d) The two (2) new offgas treaters identified as COT1 and COT2 are subject to the requirements of 40 CFR 60, Subpart J – Standards of Performance for Petroleum Refineries, since these are tail gas units serving a Claus Sulfur Recovery Plant.

New Dewatering and Thermal Desorption System

(a) The thermal desorption unit burners will be subject to the requirements for fuel gas combustion devices under 40 CFR 60, Subpart J, since the noncondensible vapors from the process will be routed to the burners.

(b) The individual drain systems, oil-water separators, and closed-vent systems and control devices constructed as part of the new dewatering and thermal desorption system shall be subject to the requirements under 40 CFR 61, Subpart FF, as this project might affect existing benzene waste streams.

(c) The thermal desorption system used to dry sludge is not subject to the requirements under 40 CFR 61, Subpart E (National Emissions Standards for Mercury) since it does not meet the definition of a sludge dryer as defined in 40 CFR 61.51(m). The thermal desorption system will not be used to reduce the moisture content in the sludge by heating to temperatures above 65 deg F directly with combustion gases. The sludge will be heated indirectly with combustion gases.

New Flares – New GOHT flare, New Coker flare, SRU flare, and HU flare

(a) The new flares identified as GOHT flare, South flare, and HU flare are subject to the control device requirements under 40 CFR 63, Subpart CC, since these flares are used for control of process vents.

(b) The new flares identified as GOHT flare, South flare, and HU flare are not subject to the requirements of 40 CFR 61, Subpart J, since these flares are not used as controls for emission units operating in benzene service.

(c) The new flares identified as GOHT flare, South flare, and HU flare are subject to the control device requirements under 40 CFR 60, Subpart J, since these flares are used for control of process vents.

(d) The new flares identified as GOHT flare, South flare, and HU flare are subject to the control device requirements under 40 CFR 63, Subpart GGGa, since these units are control devices for units that are subject to 40 CFR 63, Subpart GGGa.

Applicability of Compliance Assurance Monitoring to New and Modified Emissions Units

Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to new or modified emission units that involve a pollutant-specific emission unit and meet the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant; and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

<u>New and Modified Heaters</u>

The new and modified heaters H-201 (new), H-202 (new), H-203 (new), F-901A (new), F-901B (new), HU-1 (new), HU-2 (new), H-101 (new), H-102 (new), B-601A (new), F-401 (modified), and ISOM Heater H-1 (modified) do not use control devices to meet the applicable PM and PM-10, VOC, CO, or SO2 emissions limitations and are therefore not subject to CAM for these pollutants.

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to new or modified process heaters involved in the CXHO project, for NOx:

Emission Unit	Control Device Used	Emission Limitation (Y/N)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	Large Unit (Y/N)
HU-1	SCR	Y	52.4	100	N
HU-2	SCR	Y	52.4	100	N
H-201	SCR	Y	18.2	100	N
H-202	SCR	Y	18.2	100	N
H-203	SCR	Y	18.2	100	N

Cooling Towers 7, 8 and HU

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to new cooling towers involved in the CXHO project, for PM and PM10:

Emission Unit	Control Device Used	Emission Limitation (Y/N)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	Large Unit (Y/N)
Cooling Tower 7 (new)	Liquid drift eliminator	Y	0.5	100	N
Cooling Tower 8 (new)	Liquid drift eliminator	Y	2.2	100	N
HU Cooling Tower (new)	Liquid drift eliminator	Y	1.8	100	N

Boilers: New Boiler 1 and New Boiler 2

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to the new boilers identified as New Boiler 1 and New Boiler 2, for NOx and CO:

Emission Unit	Control Device Used	Emission Limitation (Y/N)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	Large Unit (Y/N)
New Boiler 1 and New Boiler 2	None	Y	NOx - 322.0 CO - 118.9	100	Y

Pursuant to 40 CFR 64.2(b)(vi), CAM does not apply if the Part 70 permit specifies a continuous compliance determination method, as defined in 40 CFR 64.1. New Boiler 1 and New Boiler 2 are required to operate a CEMS for both NOx and CO. Therefore, CAM does not apply to these boilers.

No. 3 Stanolind Power Station SCR Project

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to the No. 3 SPS boilers identified as boilers 1, 2, 3, 4, and 6 for NOx and CO:

Emission Unit	Control Device Used	Emission Limitation (Y/N)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	Large Unit (Y/N)
Boiler #1	SCR	Y	<100	100	N
Boiler #2	SCR	Y	<100	100	N
Boiler #3	SCR	Y	<100	100	N
Boiler #4	SCR	Y	<100	100	N
Boiler #6	SCR	Y	<100	100	N

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to the No. 3 SPS duct burners for NOx:

Emission Unit	Control Device Used	Emission Limitation (Y/N)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	Large Unit (Y/N)
Duct Burner 1	SCR	Y	<100	100	N
Duct Burner 2	SCR	Y	<100	100	N
Duct Burner 3	SCR	Y	<100	100	N
Duct Burner 4	SCR	Y	<100	100	N

Emission Unit	Control Device Used	Emission Limitation (Y/N)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	Large Unit (Y/N)
Duct Burner 5	SCR	Y	<100	100	N

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable to any of the new or modified units as part of this PSD/Significant Source Modification since none of the units are classified as large units as defined in 40 CFR 64. The applicability of CAM to the above units will be re-evaluated as part of the Part 70 permit renewal.

State Rule Applicability Determination

The applicabilities of state rules to emissions units at this source are as follows:

326 IAC 2-2 (Prevention of Significant Deterioration), 2-3 (Emission Offset), and Nonattainment NSR (326 IAC 2-1.1-5)
PSD, Emission Offset, and Nonattainment NSR applicability is discussed under the Permit Level Determination - PSD and Emission Offset section.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The operation of this petroleum refinery will greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 would apply to the emissions units at this source, however, pursuant to 326 IAC 2-4.1-1(b)(2), because this source is specifically regulated by several NESHAPs including 40 CFR 63, Subparts CC, J, QQQ, and FF, which was issued pursuant to Section 112(d) of the CAA, the new and modified emissions units under the CXHO project are exempt from the requirements of 326 2-4.1.

326 IAC 6.8-1-2 (Particulate Emissions Limitations: Lake County)
Pursuant to 326 IAC 6.8-1-2, particulate matter emissions from each of the new heaters, H-101A, H-101B, H-102, H-201, H202, H-203, F-901A, F-901B, B-601A, HU-1, HU-2, and the two new offgas treaters/thermal oxidizers for the SRU complex identified as COT1 and COT2 shall not exceed 0.03 grains per dry standard cubic foot.

Pursuant to 326 IAC 6.8-1-2(b)(3), the particulate matter emissions from New Boiler 1 and New Boiler 2 shall be no greater than one-hundredth (0.01) grain per dry standard cubic foot (dscf).

326 IAC 6.8-2 (Lake County: PM_{10} Emission Requirements)
The new process heaters H-101A, H-101B, H-102, H-201, H202, H-203, F-901A, F-901B, B-601, HU-1, HU-2, and the two new offgas treaters/thermal oxidizers for the SRU complex identified as COT1 and COT2 involved in the CXHO project are not specifically listed under 326 IAC 6.8-2. Therefore, these units are not subject to 326 IAC 6.8-2.

326 IAC 6.8-8 (Lake County: Continuous Compliance Plan)
The new process heaters H-101A, H-101B, H-102, H-201, H-202, H-203, F-901A, F-901B, B-601, HU-1, and HU-2 are not specifically listed under 326 IAC 6.8-2 through 326 IAC 6.8-11. Therefore, pursuant to 326 IAC 6.8-1-1(a)(1), 326 IAC 6.8-8 does not apply to these heaters.

326 IAC 6.8-10 (Lake County: Fugitive Particulate Matter)
The New Coker and Coke Pile that will replace the existing Coker and Coke Pile has potential to emit of fugitive PM of greater than five (5) tons per year. Therefore, it is subject to the requirements of 326 IAC 6.8-10 for batch material transfer, continuous transfer, wind erosion from storage piles, and material transportation activities, and material processing facilities, as needed..

326 IAC 6.8-2-6 (Lake County PM-10 Emissions Limitations: BP Products North America, Inc.)
BP has requested a Commissioner's Order with revised PM-10 limits that for some units are higher than the SIP limits in 326 IAC 6.8-2-6, pending a rulemaking for amendments to the Lake County PM-10 rule (326 IAC 6.8-2-6) which is scheduled for preliminary adoption on September 5, 2007. IDEM has determined that the revised limits will still demonstrate attainment of the PM-10 NAAQS, and the revised emissions limits do not represent increases in actual emissions but rather a more accurate quantification of actual existing emissions. Under 326 IAC 6.8-1-2(i), less restrictive limitations may be established by the Commissioner provided the restrictive limitations guarantee the attainment and maintenance of the particulate matter NAAQS.

Pursuant to 326 IAC 6.8-1-2(i) and 326 IAC 6.8-1-5, the Commissioner's Order No. 2007-01 allows BP to comply with the revised PM-10 limits as follows:

Unit I.D.	PM-10 Limit (lb/MMBTU) (SIP)	PM-10 Limit (lb/hr) (SIP)	Revised PM-10 Limit (lb/MMBTU) (Commissioner's Order No. 2007-01)	Revised PM-10 Limit (lb/hr) (Commissioner's Order No. 2007-01)
No. 11B Coker heaters H-101, H-102, H-103, H-104	0.004	0.741 (total)	0.0075	1.49 (total)
No. 12 Pipestill heater H-1CN	0.004	0.440	0.0075	0.894
No. 12 Pipestill heater H-1CX	0.004	0.924	0.0075	3.055
SRU Incinerator	0.004	0.090	0.0075	0.285
SRU – B/S TGU	None	0.103	0.0075	0.182
ISOM H-1	0.004	0.704	0.0075	1.416
F-200A	0.004	0.924	0.0075	1.859
F-200B	0.004	0.924	0.0075	1.859
F-401	0.004	0.130	0.0075	0.261
No.3 UF H-1	0.004	0.852	0.0075	1.788
No.3 UF H-2	0.004	0.685	0.0075	1.378
No.3 UF F-7	0.004	0.085	0.0075	0.171
Stack serving F-1, F-8A, F-8B	0.004	1.459	0.0075	2.936
F-2	0.004	1.059	0.0075	2.131
F-3	0.004	0.896	0.0075	1.803
Stack serving F-4, F-5, F-6	0.004	1.060	0.0075	2.124
F-7	0.004	0.159	0.0075	0.387
WB-301	0.004	0.250	0.0075	1.106 (total)
WB-302	0.004	0.240	0.0075	
F-801A, F-801B, F-801C	0.004	0.246(total)	0.0075	0.943 (total)
F-101	0.004	0.267	0.0075	0.536
F-102A	0.004	0.447	0.0075	0.447

326 IAC 7-4.1 (Lake County Sulfur Dioxide (SO2) Emission Limitations)
Pursuant to 326 IAC 7-4.1-1, the COT1 and COT2 offgas treaters/thermal oxidizers in the SRU complex shall burn natural gas only as supplemental fuel.

The PTE of SO2 from each of the new heaters H-101A, H-101B, H-102, H-201, H-202, H-203, F901-A, F-901B, B-601A, HU-1, and HU-2 is less than 25 tons per year. Therefore, pursuant to 326 IAC 7-1.1-1, these units are not subject to the SO2 emissions limitations in 326 IAC 7-4.1-1.

The PTE of SO2 from each of the two (2) new diesel fired burners at the dewatering and thermal desorption system is less than 25 tons per year. Therefore, pursuant to 326 IAC 7-1.1-1, these units are not subject to the SO2 emissions limitations in 326 IAC 7-4.1-1.

The PTE of SO2 from each of the duct burners used in the SCR for the 3 SPS boilers is less than 25 tons per year. Therefore, pursuant to 326 IAC 7-1.1-1, these units are subject to the SO2 emissions limitations in 326 IAC 7-4.1-1.

The PTE of SO2 from New Boiler 1 and New Boiler 2 shall each be limited to less than 25 tons per year, by blending natural gas with the refinery fuel gas used. Therefore, pursuant to 326 IAC 7-1.1-1, these units are not subject to the SO2 emissions limitations in 326 IAC 7-4.1-1. The SO2 emissions will be monitored based on a TRS (total reduced sulfur) CEMS for the mixing drum for the fuel blend used at these boilers.

326 IAC 8-4-2 (Petroleum Refineries)
Pursuant to 326 IAC 8-4-2(2), the Permittee shall equip the wastewater (oil/water) separator Tank 8a, any forebay, and openings in covers with lids or seals such that the lids or seals are in the closed position at all times except when in actual use.

326 IAC 8-4-3 (Petroleum Liquid Storage Facilities)
Pursuant to 326 IAC 8-4-3, storage tank TK-3637 has a storage capacity of greater than 39,000 gallons and contain volatile organic compounds with true vapor pressure greater than 1.52 psi. Therefore, TK-3637 is subject to the requirements of this rule.

The other storage tanks involved in the CXHO project, TK-6255 and 5052 store liquids with true vapor pressure less than 1.52 psi, and are therefore not subject to the requirements of 326 IAC 8-4-3.

The new tanks SH-1 and SH-2 will be used to store molten sulfur, and are therefore not subject to this rule.

326 IAC 8-4-8 (Leaks from Petroleum Refineries; Monitoring; Reports)
The new and modified emissions units involved in the CXHO project are located at a petroleum refinery and are subject to the requirements under 326 IAC 8-4-8. Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

326 IAC 8-9 (Volatile Organic Liquid Storage Vessels)
Pursuant to 326 IAC 8-9-2(8), storage tank TK-3637 which is subject to 40 CFR 60, Subpart Kb, are exempt from the requirements of 326 IAC 8-9.

The other storage tanks involved in the CXHO project, TK-6255 and 5052 have storage capacities greater than 39,000 gallons but store VOLs with true vapor pressures of less than 0.75 psia. Therefore, these tanks are subject to the recordkeeping and notification requirements under 326 IAC 8-9-6(h) only.

326 IAC 10-4 NOx Budget Program
Pursuant to 326 IAC 10-4, New Boiler 1 and New Boiler 2, with rated capacities exceeding 250 mmBTU/hr, will be subject to the requirements under 326 IAC 10-4, if constructed prior to 2009. Pursuant to 326 IAC 10-4-16 (Sunset) units constructed in 2009 and later shall not be subject to the NOx Budget requirements under 326 IAC 10-4.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

The Compliance Determination and Monitoring Requirements applicable to this modification are as follows:

(1) In order to demonstrate compliance with SO2, CO, and NOx emissions limitations, the Total Reduced Sulfur, CO and NOx continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with the SO2, CO, and NOx emissions limits for process heaters that are equipped with these CEMS in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

(2) In order to demonstrate compliance with the NOx emissions limitations, the SCRs shall be operated as necessary to meet the NOx emissions limits for heaters H-201, H-202 and H-203.

(3) In order to demonstrate compliance with PM and PM-10 emissions limitations, the liquid drift eliminator shall be in operation and control PM and PM-10 emissions from the Cooling Towers 2, 3, 4, 7, 8 and HU cooling tower at all times that the Cooling Towers are in operation.

(4) In order to demonstrate compliance with Condition D.1.2, following the installation of the low-NOx burners the heater H-200 shall operate using only low-NOx burners.

(5) In order to demonstrate compliance with Condition D.2.2, the Permittee shall operate the heaters HU-1, HU-2, H-201, H-202, and H-203 using only low-NOx burners.

(6) In order to demonstrate compliance with Condition D.42.3(a), the heaters F-901A and F-901B shall operate using only ultra low-NOx burners.

(7) Pursuant to 326 IAC 6.8-10-4 (formerly 326 IAC 6-1-11.1), the Permittee shall control fugitive particulate matter emissions from the New Coker and Coke Pile according to the updated Fugitive Dust Control Plan (FDCP) submitted on January 30, 2008, included as Appendix C. If it is determined that the control procedures specified in the FDCP do not demonstrate compliance with the fugitive emissions limitations, IDEM, OAQ may require that the FDCP be revised and submitted for approval.

(8) In order to demonstrate compliance with the PM, PM-10, CO, SO2, NOx, and VOC emissions limitations for the new and modified process heaters, the Permittee shall follow the following testing requirements:

(a) Tests shall be conducted on at least one new, modified or affected emission units from each identified testing group that are included in the CXHO project, utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C - Performance Testing. PM-10 includes both filterable and condensible PM-10. These tests shall be repeated at least once every five years from the date of the previous valid compliance demonstration.

(b) Tests shall be conducted in accordance with the following deadlines:

(1) For a group that includes new or modified emission units: within 180 days of the installation of a new emission unit, or modification of an existing emission unit within that group.

(2) For a group that includes only existing affected units: within 180 days of the startup of New Coker.

(c) The emissions units to be tested in order to demonstrate compliance with Prevention of Significant Deterioration (326 IAC 2-2), Emission Offset (326 IAC 2-3) and Nonattainment NSR (326 IAC 2-1.1-5) minor limits shall be grouped as follows:

Pollutant	Test Group ID	Emission Units in Group
CO	CO-1	11A PS heaters H-1X, H-2, H-3 11C PS heaters H-200, H-300 4 UF heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, F-8B ARU heaters F-200A, F-200B BOU heater F-401 CFHU heaters F-801A, F-801B CRU heaters F-101, F-102 ISOM heater H-1
	CO-2	DDU heaters WB-301, WB-302
	CO-3	HU heater B-501
	CO-4	CFHU heater F-801C
	No stack test required (equipped with CO CEMS)	New Coker heaters H-201, H-202, H-203 12 PS heaters H-101A, H-101B, H-102 DHT heater B-601A New HU heaters HU-1, HU-2 SRU COT1, COT2 FCU 500, FCU 600 3 SPS boilers/duct burners 1, 2, 3, 4, 6 New Boiler 1, New Boiler 2
VOC and PM/PM-10 * VOC test group only	PM/VOC-1	New Coker heaters H-201, H-202, H-203
	PM/VOC-2	New HU heaters HU-1, HU-2
	PM/VOC-3	SRU COT1, COT2
	PM/VOC-4	11C PS heater H-200 12 PS heaters H-101A, H-101B, H-102 BOU heater F-401 GOHT heaters F-901A, F-901B DHT heater B-601a ISOM heater H-1 HU heater B-501
	PM/VOC-5	11A PS heaters H-1X, H-2, H-3 11C PS heater H-300 4UF heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A,F-8B ARU heaters F-200A, F-200B CFHU heaters F-801A, F-801B, F-801C CRU heaters F-101, F-102 DDU heaters WB-301, WB-302

Pollutant	Test Group ID	Emission Units in Group
	VOC-6*	3 SPS boilers 1, 2, 3, 4, 6
	PM/VOC-7	New Boiler 1, New Boiler 2
	PM/VOC-8	FCU 500
	PM/VOC-9	FCU 600
NOx	NOx-1	CFHU heater F-801C GOHT heaters F-901A, F-901B DDU heater WB-301
	NOx-2	11C PS heater H-200
	NOx-3	CRU heaters F-101, F-102
	NOx-4	4UF heaters F-3, F-4, F-8A, F-8B ARU heaters F-200A, F-200B ISOM heater H-1
	NOx-5	4UF heater F-2
	NOx-6	11A PS heater H-1X
	NOx-7	11C PS heater H-300
	NOx-8	11A PS heater H-2, H-3 4UF heaters F-1, F-5, F-6, F-7 BOU heater F-401
	NOx-9	CFHU heaters F-801A, F-801B
	NOx-10	HU heater B-501
	NOx-11	DDU heater WB-302
	NOx-12	SRU COT1, COT2
	No stack test needed (NOx CEMS)	3 SPS boilers 1, 2, 3, 4, 6, New Boiler 1, New Boiler 2 New Coker heaters H-201, H-202, H-203 12 PS heaters H-101A, H-101B, H-102 New HU heaters HU-1, HU-2, and FCU 500, FCU 600

(d) Within 180 days of the startup of New Coker (#2 Coker), in order to demonstrate compliance with the PM-10 emission factor limit from the SCR stacks at No. 3 Stanolind Power Station (3 SPS), testing shall be conducted on one (1) of the five (5) stacks for 3 SPS boiler/SCR stacks, utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C - Performance Testing. PM-10 includes filterable and condensible PM-10. This test shall be repeated at least once every five years from the date of the previous valid compliance demonstration.

(e) Compliance with the emissions limits for each emission unit or test group shall be determined as follows:

$$T = \left(\sum_{i=1}^{n} T_i \right) / n$$

Where:

T = average of IDEM approved stack test results for emission unit or all units within that same group over the previous 12 month period
T_i = average of multiple runs during Test #i
n = number of IDEM approved stack tests during previous 12 month period

(9) After the installation of the continuous BTU analyzer at the mixing drums for supplying fuel to heaters and boilers, the continuous BTU analyzer shall be calibrated, maintained, and operated for determining compliance with the firing rate limits for heaters.

(a) Continuously monitor the fuel flow rates at the heaters and boilers;

(b) Conduct a monthly analysis of fuel gas samples taken once per week in order to determine monthly averaged BTU content of the fuel gas in the mixing drums prior to installation of the continuous BTU analyzers; and

(c) Determine the monthly firing rates for the heaters based on the fuel flow rates at each heater and the monthly averaged BTU content of the fuel gas in the mixing drums.

(10) After the startup of the New Coker, in order to demonstrate compliance with the PSD, EO and nonattainment NSR minor limits, the exhaust from WARP projects at FCU 500, FCU 600 and No. 11 PS shall be routed to the designated flares with a flame present at all times.

(11) Within 180 days of the installation of the VRU or VCU at the marine loading dock, the Permittee shall perform VOC testing at the outlet of the VRU/VCU when loading gasoline utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C - Performance Testing. This test shall be repeated at least once every five years from the date of the previous valid compliance demonstration.

Compliance with the emissions limit for the VRU/VCU shall be determined as follows:

$$T = \left(\sum_{i=1}^{n} T_i \right) / n$$

Where:

T = average of IDEM approved stack test results over the previous 12 month period
T_i = average of multiple runs during Test #i
n = number of IDEM approved stack tests during previous 12 month period

(12) After the installation of the VRU/VCU at the marine loading dock, the VRU/VCU shall be in operation and control VOC emissions at all times gasoline loading is being performed at the marine loading dock.

(13) The Permittee shall take weekly measurements of the total dissolved solids (TDS) in the water input to Cooling Towers No. 2, 3, 4, 7, 8 and HU cooling tower. If the TDS limitation is exceeded, the Permittee shall perform quantitative water analyses and shall take the remedial action necessary to correct the problem.

(14) The Permittee shall visually inspect the water going to Cooling Towers No. 2, 3, 4, 7 and 8 for liquid VOC, including but not limited to the indication of a sheen, at least once per week. If VOC is observed, the Permittee will take the remedial action necessary to correct the problem.

(15) The new and modified emissions units involved in the CXHO project are located at a petroleum refinery and are subject to the requirements under 326 IAC 8-4-8. Pursuant to 326 IAC 8-4-8, for the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

(16) For all pumps involved in heavy liquid service, in order to demonstrate compliance with the PSD, EO, and nonattainment NSR minor limits, the Permittee shall control leaks of VOC according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service. The Permittee shall update the LDAR Plan to indicate that the methodologies in 40 CFR 60.482 shall apply to all pumps in heavy liquid service and shall submit a copy of the revised LDAR Plan to IDEM, OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

These compliance determination and monitoring conditions are necessary in order to ensure compliance with the emissions limitations in the permit. Compliance with the emissions limits, in conjunction with the startup and shutdown schedule of emissions units and installation schedule for control devices and the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant thresholds at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable.

Proposed Changes

The modified A, D, and E sections of the permit No: T 089-6741-00453 have been included in their entirety as Appendix D to this Technical Support Document. These changes have been summarized below:

(1) Section A.3 of the permit has been modified in order to incorporate description changes related to the CXHO project.

(2) In December 2005 Innovene USA LLC, a wholly owned subsidiary of BP, sold the INEOS Whiting chemical plant to INEOS. INEOS is a separate corporation that is not owned by BP. Due to this changed relationship, IDEM, OAQ has decided to reexamine whether the BP Whiting refinery and the INEOS chemical plant are part of the same major source. Section A.2 has been updated accordingly.

(3) The following D and E sections have been revised in order to incorporate descriptive changes and include emissions limitations and standards, compliance determination, compliance monitoring, recordkeeping and reporting requirements for new and existing units related to the CXHO project.

Section	Facility	Emissions Units/Description of Changes
D.0	Entire source	Testing requirements for CXHO project Recordkeeping and reporting requirements for CXHO phased construction project
D.1	No.11 pipe still	Installation of ultra low-NOx burners on H-200; Affected Units H-1X, H-2, H-3, H-300; Redundant tank 8 oil water separator 11A and 11C PS WARP project
D.2	No. 11B Coker and New Coker	Shutdown of heaters H-101, H-102, H-103, H-104 and shutdown of existing coke storage, New Coker heaters H-201, H-202, H-203 and new coke handling and storage
D.3	No. 12 pipe still	New heaters H-101A, H-101B, H-102 and new tank TK-6255; shutdown of heaters H-1AN, H-1AS, H-1CN, H-2, H-1B and H-1CX
D.4	Sulfur Recovery Unit	New COT1 and COT2 tail gas units, tanks SH-1 and SH-2; Shutdown of B/S TGU, SBS TGU, SBS cooling tower and SRU standby incinerator
D.5	VRU 100 and VRU 200	VRU 100/200 WARP project VRU 100 and 200 TAR (part of FCU 500 TAR)
D.6	VRU 300 and VRU 400	New VRU 400 for New Coker
D.8	Propylene Concentration Unit	Affected unit
D.9	Isomerization Unit	Modified heater ISOM H-1
D.10	Aromatic Recovery Unit	Affected units F-200A, F-200B
D.11	Blending Oil Unit	Modified heater F-401
D.13	No. 4 Treating Plant	Shutdown of unit
D.15	No.3 UF	Shutdown, including heaters H-1, H-2, F-7

Section	Facility	Emissions Units/Description of Changes
		shutdown
D.16	No. 4 UF	Affected units: F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, F-8B
D.17	Hydrogen Unit	Affected unit B-501
D.18	The Distillate Desulfurizer Unit	Affected units WB-301, WB-302
D.19	The Cat Feed Hydrotreating Unit	Affected units: F-801A, F-801B, F-801C
D.20	The Catalytic Refining Unit	Affected units: F-101, F-102A
D.21	The Fluidized Catalytic Cracking Unit (FCU) 500	Affected unit FCU 500 FCU 500 WARP, FCU 500 TAR
D.22	The Fluidized Catalytic Cracking Unit (FCU) 600	Affected unit FCU 600, FCU 600 WARP FCU 600 TAR
D.23	No. 1 Stanolind Power Station	Future shutdown of boilers 3, 4, 5, 6, 7
D.24	No. 3 Stanolind Power Station	Modified units: Boilers 1, 2, 3, 4, 6 - replace burners, installation of SCR on boilers Five (5) new duct burners
D.25	Fluidized Bed Incinerator	Shutdown FBI Add new dewatering and thermal desorption unit and two (2) new diesel fired burners at 4 mmBTU/hr each
D.26	Wastewater treatment plant 544	New storage tank 5052, brine treatment system with new tanks TK-101, TK-102, TK-103, TK-104A, TK-104B, TK-105A, and TK-105B
D.27	Oil Movements	Reconstructed tank TK-3637
D.31	Cooling Towers	Controls installed on cooling towers 2, 3, 4; New cooling towers 7and 8
D.34	Marine dock facility	Installation of Vapor Recovery/Vapor Control Unit Modified Tank BT-002
D.35	Hydrocarbon Flares	New flares GOHT, South flare
D.36	OSBL	Affected unit
D.37	Distillate Hydrotreating Unit	Shutdown heater B-601, New heater B-601A
D.42 (new)	New Gas Oil Hydrotreater	New heaters F-901A, F-901B
D.43 (new)	New Hydrogen Unit	New heaters HU-1 and HU-2, HU flare,HU cooling tower
D.44(new)	Additional units - non-CXHO contemporaneous projects	3 emergency firepump engines (390 HP), 2 boilers at 580 mmBTU/hr each
E.20	Boilers	Subpart DDDDD - vacated
E.21	Entire Source	NESHAP Subpart GGGGG
E.22	New Boilers	NSPS Subpart Db
E.23	Firepump engines	NSPS Subpart IIII
E.24	Storage Tank D-424 and other insignificant activities	NESHAP Subpart EEEE
E.25	Entire Source	NSPS Subpart GGGa
E.26	Entire Source	NSPS Subpart VVa
Report Forms	Entire Source	

(4) The NESHAP for Site Remediation, 40 CFR 63, Subpart GGGGG has been incorporated in its entirety. Section E.21, which included a short version of this NESHAP, has been modified as shown in Appendix D to this Technical Support Document.

(5) The Table of Contents has been modified to incorporate new conditions and renumber existing conditions in the permit.

In addition, the changes listed below have been made to Sections B and C of the Part 70 Operating Permit No. 089-6741-00453 (~~strikeout~~ to show deletions and **bold** to show additions):

Change No. 1:

The IDEM, OAQ, Compliance Section telephone and fax numbers have been revised throughout the permit. The mailcodes have been added to the addresses of Office of Air Quality - Compliance, Permits, Compliance Data, Technical Support and Modeling and Asbestos sections.

Change No. 2:

The clean unit and pollution control project (PCP) provisions of the U.S. EPA's NSR Reform rules were vacated on June 24, 2005 by a United States Court of Appeals for the District of Columbia. Condition C.21 has been modified as follows:

C.21 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2] [326 IAC 2-3]

(a) Records of all required monitoring data, reports and support information required by this Permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner or the Hammond Department of Environmental Management, makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner or the Hammond Department of Environmental Management, within a reasonable time.

(b) Unless otherwise specified in this permit, all record keeping requirements not already legally required shall be implemented within ninety (90) days of the effective date of this permit.

(c) If there is a reasonable possibility that a "project" (as defined in 326 IAC 2-2-1(qq) or 326 IAC 2-3-1(ll)) at a major source other than projects ~~than projects at a Clean Unit~~ **at a source with a Plant-wide Applicability Limitation (PAL)** which is not part of a "major Modification" (as defined in 326 IAC 2-2-1(ee) or 326 IAC 2-3-1(z)) ~~may result in significant emissions increase~~ and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(rr) or 326 IAC 2-3-1(mm), the Permittee shall comply with the following:

(1) Prior to commencing the construction of "project" (as defined in 326 IAC 2-2-1(qq) or 326 IAC 2-3-1(ll)) document and maintain the following records:

(A) A description of the project;

(B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project;

(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:

(i) Baseline actual emissions;

(ii) Projected actual emissions;

(iii) Amount of emissions excluded under section 326 IAC 2-2-1(rr)(2)(A)(iii) or 326 IAC 2-3-1(mm)(2)(A)(iii); and

(iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.

(2) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in (1)(B) above; and

(3) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) ten years following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emission unit.

Change No. 3

Pursuant to 40 CFR 63.2338(b), storage tank D-424 (which stores organic liquids) and any equipment at this source that meets the definition of an affected source under 40 CFR 63.2334 shall comply with the requirements of 40 CFR 63, Subpart EEEE.

Conditions C.25, C.26, C.27, and C.28 of the permit, which include the requirements under 40 CFR 63, Subpart EEEE have been deleted and the requirements of 40 CFR 63, Subpart EEEE that pertain to storage tank D-424 are included in Section E.24.

~~C.25 General Provisions Relating to HAPs [326 IAC 20-1] [40 CFR Part 63, Subpart A] [Table 12 to 40 CFR Part 63, Subpart EEEE] [40 CFR 63.2398]~~

~~(a) The provisions of 40 CFR Part 63, Subpart A- General Provisions, which are incorporated by reference as 326 IAC 20-1-1, apply to any storage vessel at this source that is subject to the provisions of 40 CFR 63, Subpart EEEE, except when otherwise specified by Table 12 to 40 CFR Part 63, Subpart EEEE. The Permittee shall comply with these requirements on and after the effective date of the National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution, Non-Gasoline.~~

~~(b) Since the applicable requirements associated with the compliance options are not included and specifically identified in this permit, the permit shield authorized by the B section of this permit in the condition titled Permit Shield, and set out in 326 IAC 2-7-15 does not apply to paragraph (a) of this condition.~~

~~C.26 National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution, non-Gasoline [40 CFR Part 63, Subpart EEEE]~~

~~The Permittee shall comply with the following requirements for any storage vessel at the source that is subject to the provisions of 40 CFR 63, Subpart EEEE (National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution, Non-Gasoline). A copy of this rule is available on the US EPA Air Toxics Website at http://www.epa.gov/ttn/atw/orgliq/orgliqpg.html.~~

~~(a) Pursuant to 40 CFR 63.2342(b)(1), the Permittee shall comply with the emission limitations, operating limits, and work practice standards for any existing affected sources no later than the date three (3) years after the effective date of the final rule for 40 CFR Part 63, Subpart EEEE, except as provided in paragraph (b)(2) of 40 CFR 63.2342.~~

~~(b) Pursuant to 40 CFR 63.2342(b)(2), any floating roof storage tanks at existing affected sources shall be in compliance with the work practice standards in Table 4 to 40 CFR Part 63, Subpart EEEE, item 1, at all times after the next degassing and cleaning activity or within 10 years after the effective date of the final rule for 40 CFR Part 63, Subpart EEEE, whichever occurs first. If the first degassing and cleaning activity occurs during the 3 years following the effective date of the final rule for 40 CFR Part 63, Subpart EEEE, the compliance date is the date three (3) years after the effective date of the final rule for 40 CFR Part 63, Subpart EEEE.~~

~~(c) Since the applicable requirements associated with the compliance options are not included and specifically identified in this permit, the permit shield authorized by the B section of this permit in the condition titled Permit Shield, and set out in 326 IAC 2-7-15 does not apply to paragraphs (a), (b), and (c) of this condition.~~

~~(d) The definition in 40 CFR 63, Section 63.2 and in 40 CFR 63.2406 are applicable to this Permittee.~~

~~C.27 Notifications Requirements [40 CFR 63.2382]~~

~~The Permittee shall submit the following notifications for all storage vessels subject to the requirements of 40 CFR 63, Subpart EEEE:~~

~~(a) Initial Notification. The Permittee shall submit the Initial Notification no later than 120 calendar days after the effective date of 40 CFR Part 63, Subpart EEEE.~~

~~(b) The Permittee shall submit the Notification of Intent to conduct a performance test at least 60 calendar days before it is initially scheduled to begin as required in 40 CFR Part 63, Section 63.7(b)(1).~~

~~(c) Notification of Compliance Status. If the Permittee are required to conduct a performance test, design evaluation, or other initial compliance demonstration as specified in Table 5, 6, or 7 to 40 CFR Part 63, Subpart EEEE, the Permittee shall submit a Notification of Compliance Status. The Notification of Compliance Status shall include the information required in 40 CFR Part 63, Section 63.999(b) and in paragraphs (d)(2)(i) through (viii) of 40 CFR 63.2382.~~

~~C.28 Requirement to Submit a Significant Permit Modification Application [326 IAC 2-7-12] [326 IAC 2-7-5]~~

~~The Permittee shall submit an application for a significant permit modification to IDEM, OAQ to include information regarding which compliance option or options will be chosen in the Title V permit.~~

~~(a) The significant permit modification application shall be consistent with 326 IAC 2-7-12, including information sufficient for IDEM, OAQ to incorporate into the Title V permit the applicable requirements of 40 CFR 63, Subpart EEEE, a description of the affected source and activities subject to the standard, and a description of how the Permittee will meet the applicable requirements of the standard.~~

~~(b) The significant permit modification application shall be submitted no later than the date the Notification of Compliance Status is due.~~

~~(c) The significant permit modification application shall be submitted to:~~

~~Indiana Department of Environmental Management~~
~~Permits Branch, Office of Air Quality~~
~~100 North Senate Avenue~~
~~Indianapolis, Indiana 46204-2251~~

Change No. 4:

The boilers and process heaters at this source were subject to the requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63, Subpart DDDDD (Industrial, Commercial, and Institutional Boilers and Process Heaters). However, on July 30, 2007, 40 CFR 63, Subpart DDDDD has been vacated in its entirety.

The permit conditions that included requirements under this NESHAP have been deleted throughout the entire permit.

Conclusion and Recommendation

The construction and operation of this proposed modification shall be subject to the conditions of the attached proposed Significant Source Modification No. 089-25484-00453 and Significant Permit Modification No. 089-25488-00453. The staff recommend to the Commissioner that this Significant Source Modification No. 089-25484-00453 and Significant Permit Modification No. 089-25488-00453 be approved.

Indiana Department of Environmental Management
Office of Air Quality

Appendix C and E to the
Technical Support Document (TSD) for a
Significant Source Modification (SSM) of a Part 70 Source and
Significant Permit Modification (SPM) of Part 70 Operating Permit

Draft Calculations
(Public Notice Version)

BP Products North America Inc., Whiting Business Unit
Significant Source Modification No.: 089-25484-00453
Significant Permit Modification No.: 089-25488-00453

Table Number	Description
1	Emission Factors for Carbon Monoxide Emissions
2	Emission Factors for Lead Emissions
3	Emission Factors for Mercury Emissions
4	Emission Factors for Beryllium Emissions
5	Emission Factors for Nitrogen Oxides Emissions
6	Emission Factors for PM (Filterable) Emissions
7	Emission Factors for PM10 and PM2.5 (Filterable + Condensable) Emissions
8	Emission Factors for Sulfuric Acid Mist Emissions
9	Emission Factors for Sulfur Dioxide Emissions
10	Emission Factors for Volatile Organic Compound Emissions
11	Project Combustion Emissions
12	1999 Combustion Emissions
13	2000 Combustion Emissions
14	2001 Combustion Emissions
15	2002 Combustion Emissions
16	2003 Combustion Emissions
17	2004 Combustion Emissions
18	Baseline FBI Beryllium Emissions
19	Project Sulfur Recovery Complex Emissions
20	1999 Sulfur Recovery Complex Emissions
21	2000 Sulfur Recovery Complex Emissions
22	2001 Sulfur Recovery Complex Emissions
23	2002 Sulfur Recovery Complex Emissions
24	2003 Sulfur Recovery Complex Emissions
25	2004 Sulfur Recovery Complex Emissions
26	Project Cooling Tower Emissions
27	2000 Cooling Tower Emissions
28	2001 Cooling Tower Emissions
29	2002 Cooling Tower Emissions
30	2003 Cooling Tower Emissions
31	2004 Cooling Tower Emissions
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33	Project Fugitive Dust Emissions - Coke Handling (Alternate Operating Scenario)
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35	2001-2002 Coke Handing Emissions
36	2001-2002 Fugitive Emissions from Paved Roads
37	2001-2002 Fugitive Emissions from Unpaved Roads
38	Project Flare Pilot and Purge Gas Combustion Emissions (Normal Operation)
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40	Fugitive Emission Calculations for 4 Ultraformer
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42	Fugitive Emission Calculations for 12 Pipestill
43	Fugitive Emission Calculations for Distillate Hydrotreater (DHT)
44	Fugitive Emission Calculations for New Coker (#2 Coker)
45	Fugitive Emission Calculations for Existing Coker (11 PS)
46	Fugitive Emission Calculations for Gas Oil Hydrotreater (GOHT)
47	Fugitive Emission Calculations for New Hydrogen Unit (3rd Party SMR)
48	Fugitive Emission Calculations for OSBL
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51 Fugitive Emission for Claus Offgas Treater 2
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53 Fugitive Emission for ARU
54 Fugitive Emission for BOU
55 Fugitive Emission for ISOM
56 Fugitive Emission for VRU300
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62 2003 Marine Loading Emissions
63 2004 Marine Loading Emissions
64 Project Fluidized Catalytic Cracking Emissions
65 1999 Fluidized Catalytic Cracking Emissions
66 2000 Fluidized Catalytic Cracking Emissions
67 2001 Fluidized Catalytic Cracking Emissions
68 2002 Fluidized Catalytic Cracking Emissions
69 2003 Fluidized Catalytic Cracking Emissions
70 2004 Fluidized Catalytic Cracking Emissions
70a Historical Reported and PTE SO2 Emissions for Fluidized Catalytic Cracking Unit 600
71 Existing Unit Volatile Organic Compound Emissions
72 Existing Unit Nitrogen Oxide Emissions
73 Existing Unit Sulfur Dioxide Emissions
74 Existing Unit PM (Filterable) Emissions
75 Existing Unit PM10/PM2.5 (Filterable + Condensable) Emissions
76 Existing Unit Carbon Monoxide Emissions
77 Existing Unit Sulfuric Acid Mist Emissions
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Appendix E

Fugitives 11A WARP
11A WARP Sewer Counts
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Fugitives 11C WARP
11C WARP Sewer Counts
Increased DDU - Flare 11B WARP
Increased DDU - Flare 11C WARP
Fugitives FCU500 WARP
FCU500 WARP Sewer Counts
Fugitives FCU600 WARP

FCU600 WARP Sewer Counts
Increased FCU Flare - F600 WARP
Fugitives FCU600TAR
Fugitives VRU 100 WARP
Fugitives VRU 200 WARP
VRU100200 WARP Sewer Counts
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Dewatering System
Thermal Desporption
Burner Emissions
Fugitive Emissions

Table C.1. Emission Factors for Carbon Monoxide Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	H-2	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	H-3	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
11C PS											
Cont	H-200	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	H-300	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Coker											
SD	H-101[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-102[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-103[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-104[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
New Coker (#2 Coker)											
New	H-201					0.019	lb/10[6] Btu	Design[4]	Guarantee[11]		0.019
New	H-202					0.019	lb/10[6] Btu	Design[4]	Guarantee[11]		0.019
New	H-203					0.019	lb/10[6] Btu	Design[4]	Guarantee[11]		0.019
12PS											
SD	H-1AN[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-1AS[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-1B[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-2[14]	0.0001	lb/10[6] Btu	Stack Test[3]	Source Specific[8]					0.0001	
SD	H-1CN[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-1CX[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
New	H-101A					0.019	lb/10[6] Btu	Design[4]	Guarantee[11]		0.019
New	H-102					0.019	lb/10[6] Btu	Design[4]	Guarantee[11]		0.019
New	H-101B					0.019	lb/10[6] Btu	Design[4]	Guarantee[11]		0.019
Hydroprocessing											
3UF											
SD	H-1[13]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	H-2[13]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	F-7[13]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
4UF											
Oth	F-1	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-8A	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-8B	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-2	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-3	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-4	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-5	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-6	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-7	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
ARU											
Oth	F-200A	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-200B	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
BOU											
Mod	F-401	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
CFHU											
Oth	F-801A	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-801B	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-801C	0.0001	lb/10[6] Btu	Stack Test[6]	Source Specific[8]	0.0001	lb/10[6] Btu	Stack Test[6]	Source Specific[8]	0.0001	0.0001
GOHT											
New	F-901A					0.02	lb/10[6] Btu	Design[4]	Guarantee[11]		0.02
New	F-901B					0.02	lb/10[6] Btu	Design[4]	Guarantee[11]		0.02
CRU											
Oth	F-101	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
Oth	F-102	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
DDU											
Oth	WB-301	0.04	lb/10[6] Btu	Permit Limit	Permit Limit[12]	0.04	lb/10[6] Btu	Permit Limit	Permit Limit[12]	0.04	0.04
Oth	WB-302	0.04	lb/10[6] Btu	Permit Limit	Permit Limit[12]	0.04	lb/10[6] Btu	Permit Limit	Permit Limit[12]	0.04	0.04
DHT											
New	B-601A					0.04	lb/10[6] Btu	Design[4]	Guarantee[11]		0.04
ISOM											
Mod	H-1	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]	0.082	0.082
HU											
Oth	B-501	0.02	lb/10[6] Btu	Design[4]	Guarantee[11]	0.02	lb/10[6] Btu	Design[4]	Guarantee[11]	0.02	0.02
New HU (3rd Party SMR)											
New	HU-1[15]					0.015	lb/10[6] Btu	Design[4]	Guarantee[11]		0.015
New	HU-2[15]					0.015	lb/10[6] Btu	Design[4]	Guarantee[11]		0.015
Utilities											
1SPS											
SD	Boiler 3[13]	0.049	lb/10[6] Btu	Stack Test[1]	Source Specific[8]						
SD	Boiler 4[13]	0.049	lb/10[6] Btu	Stack Test[1]	Source Specific[8]						
SD	Boiler 5[13]	0.248	lb/10[6] Btu	Stack Test[1]	Source Specific[8]						
SD	Boiler 6[13]	0.248	lb/10[6] Btu	Stack Test[1]	Source Specific[8]						
SD	Boiler 7[13]	0.248	lb/10[6] Btu	Stack Test[1]	Source Specific[8]						
Fluidized Catalytic Cracking											
Oth	FCU 500	26	PPM	CEMS[5]	Source Specific[8]	42	PPM	CEMS	Source Specific[10]	N/A	N/A
Mod[16]	FCU 600	22	PPM	CEMS[5]	Source Specific[8]	41	PPM	CEMS	Source Specific[10]	N/A	N/A
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	Beavon-Stretford Tail Gas Unit[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
SD	SRU Incinerator[14]	84	lb/10[6] scf	AP-42[2]	EF B Rating[9]					0.082	
New	New COT 1					0.05	lb/10[6] Btu	Design[4]	Guarantee[11]		0.05
New	New COT 2					0.05	lb/10[6] Btu	Design[4]	Guarantee[11]		0.05

Table C.1. Emission Factors for Carbon Monoxide Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
New Flares											
New	GOHT Flare: Pilot					84	lb/10^6 scf	AP-42[2]	EF B Rating[9]		0.082
New	GOHT Flare: Purge					0.37	lb/10^6 Btu	AP-42[7]	EF B Rating[9]		0.37
New	South Flare: Pilot					84	lb/10^6 scf	AP-42[2]	EF B Rating[9]		0.082
New	South Flare: Purge					0.37	lb/10^6 Btu	AP-42[7]	EF B Rating[9]		0.37
New	HU Flare: Pilot					84	lb/10^6 scf	AP-42[2]	EF B Rating[9]		0.082
Lakefront											
SD	FBI (99-01)	0.1	lb/unit feed	Stack Test	Source Specific[8]					N/A	
SD	FBI (02-04)	0.012	lb/unit feed	Stack Test	Source Specific[8]					N/A	

Emission Factor Source References

[1] Based on stack test performed for BP Whiting Refinery in March 1993.

[2] U.S. AP-42. EPA. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4, "Natural Gas Combustion," Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NOx) AND CARBON MONOXIDE

[3] Based on stack test performed for BP Whiting Refinery in March 2002.

[4] Based on design requirements.

[5] Baseline actual emissions calculated using CEMS data for 2002-2004. Emissions prior to 2002 were conservatively calculated using minimum (annually averaged) CEMS data from 2002-2004.

[6] Based on stack test performed for BP Whiting Refinery in September 2003.

[7] U.S. AP-42. EPA. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.5, "Industrial Flares" Table 13.5-1. EMISSION FACTORS FOR FLARE OPERATION; (September 1991).

Justification References

[8] Based on most current source specific data.

[9] The carbon monoxide (CO) emission factors from AP-42 are used in the refinery industry as a standard when source specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.

[10] Based on source specific data.

[11] Based on anticipated vendor guarantee to satisfy design requirement.

[12] Emission factor based on emission limit in Title V operating permit.

Emission Unit References

[13] Existing unit being shutdown within the CXHO project contemporaneous period.

[14] Existing unit being shutdown as part of CXHO project.

[15] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same CO emission factors.

[16] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.2. Emission Factors for Lead Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	H-2	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	H-3	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
11C PS											
Cont	H-200	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	H-300	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Coker											
SD	H-101[5]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-102[5]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-103[5]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-104[5]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
New Coker (#2 Coker)											
New	H-201					5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	H-202					5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	H-203					5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]		4.90E-07
12PS											
SD	H-1AN[5]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-1AS[5]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-1B[5]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-2[5]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-1CN[5]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-1CX[5]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
New	H-101A					5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	H-102					5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	H-101B					5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]		4.90E-07
Hydroprocessing											
3UF											
SD	H-1[4]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	H-2[4]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	F-7[4]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
4UF											
Oth	F-1	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-8A	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-8B	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-2	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-3	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-4	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-5	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-6	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-7	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
ARU											
Oth	F-200A	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-200B	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
BOU											
Mod	F-401	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
CFHU											
Oth	F-801A	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-801B	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-801C	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
GOHT											
New	F-901A					5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	F-901B					5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]		4.90E-07
CRU											
Oth	F-101	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	F-102	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
DDU											
Oth	WB-301	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
Oth	WB-302	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
DHT											
New	B-601A					5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]		4.90E-07
ISOM											
Mod	H-1	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
HU											
Oth	B-501	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]	4.90E-07	4.90E-07
New HU (3rd Party SMR)											
New	HU-1[6]					5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	HU-2[6]					5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]		4.90E-07
Utilities											
1SPS											
SD	Boiler 3[4]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	Boiler 4[4]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	Boiler 5[4]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	Boiler 6[4]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	Boiler 7[4]	5.00E-04	lb/10[6] scf	AP-42[1]	EF D Rating[2]					4.90E-07	
Fluidized Catalytic Cracking											
Oth	FCU 500	2.55E-04	lb/1000 lb coke burned	Industry Paper[3]		2.55E-04	lb/1000 lb coke burned	Industry Paper[3]		N/A	N/A
Mod[7]	FCU 600	2.55E-04	lb/1000 lb coke burned	Industry Paper[3]		2.55E-04	lb/1000 lb coke burned	Industry Paper[3]		N/A	N/A

Table C.2. Emission Factors for Lead Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	Beavon-Stretford Tail Gas Unit[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
SD	SRU Incinerator[5]	5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]					4.90E-07	
New	New COT 1					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	New COT 2					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New Flares											
New	GOHT Flare: Pilot					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	GOHT Flare: Purge					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	South Flare: Pilot					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	South Flare: Purge					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
New	HU Flare: Pilot					5.00E-04	lb/10^6 scf	AP-42[1]	EF D Rating[2]		4.90E-07
Lakefront											
SD	FBI (99-01)	3.95E-06	lb/ton feed								
SD	FBI (02)	1.98E-05	lb/ Mgal feed								
SD	FBI (03)	1.98E-05	lb/ Mgal feed								
SD	FBI (04-06)	1.98E-05	lb/ Mgal feed								

Emission Factor Source References

[1] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4 "Natural Gas Combustion," Table 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION; (July 1998).

Justification References

[2] The Lead emission factors from AP-42 are used in the refinery industry as a standard when site specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.

[3] R. Bertrand and J. Siegell. Emission of Trace Compounds from Catalytic Cracking Regenerators, Environmental Progress (volume 21, No. 3). October 2002. Pages 163-167

Footnotes

[4] Existing unit being shutdown within the CXHO project contemporaneous period.

[5] Existing unit being shutdown as part of CXHO project.

[6] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same lead emission factors.

[7] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.3. Emission Factors for Mercury Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	H-2	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	H-3	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
11C PS											
Cont	H-200	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	H-300	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Coker											
SD	H-101[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-102[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-103[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-104[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
New Coker (#2 Coker)											
New	H-201					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	H-202					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	H-203					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
12PS											
SD	H-1AN[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-1AS[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-1B[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-2[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-1CN[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-1CX[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
New	H-101A					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	H-102					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	H-101B					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
Hydroprocessing											
3UF											
SD	H-1[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	H-2[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	F-7[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
4UF											
Oth	F-1	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-8A	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-8B	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-2	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-3	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-4	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-5	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-6	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-7	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
ARU											
Oth	F-200A	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-200B	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
BOU											
Mod	F-401	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
CFHU											
Oth	F-801A	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-801B	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-801C	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
GOHT											
New	F-901A					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	F-901B					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
CRU											
Oth	F-101	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	F-102	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
DDU											
Oth	WB-301	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
Oth	WB-302	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
DHT											
New	B-601A					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
ISOM											
Mod	H-1	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
HU											
Oth	B-501	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]	1.80E-07	1.80E-07
New HU (3rd Party SMR)											
New	HU-1[6]					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	HU-2[6]					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
Utilities											
1SPS											
SD	Boiler 3[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	Boiler 4[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	Boiler 5[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	Boiler 6[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	Boiler 7[4]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
Fluidized Catalytic Cracking											
Oth	FCU 500	1.00E-06	lb/1000 lb coke burned	Engineering Estimate[3]		1.00E-06	lb/1000 lb coke burned	Engineering Estimate[3]		N/A	N/A
Mod[7]	FCU 600	1.00E-06	lb/1000 lb coke burned	Engineering Estimate[3]		1.00E-06	lb/1000 lb coke burned	Engineering Estimate[3]		N/A	N/A

Table C.3. Emission Factors for Mercury Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	Beavon-Stretford Tail Gas Unit[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
SD	SRU Incinerator[5]	1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]					1.80E-07	
New	New COT 1					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	New COT 2					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New Flares											
New	GOHT Flare: Pilot					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	GOHT Flare: Purge					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	South Flare: Pilot					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	South Flare: Purge					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
New	HU Flare: Pilot					1.84E-04	lb/10^6 scf	API/WSPA[1]	Industry Factor[2]		1.80E-07
Lakefront											
SD	FBI (99-01)	2.7127E-05	lb/ton feed								
SD	FBI (02-06)	0.00013574	lb/Mgal feed								

Emission Factor Source References

[1] Emissions are based on API / WSPA Emission Factors for Boilers / Heaters using Process Gas, 1998 (Table ES-1).

Justification References

[2] Industry emission factor.

[3] Emission factor based on Engineering Estimate.

Footnotes

[4] Existing unit being shutdown within the CXHO project contemporaneous period.

[5] Existing unit being shutdown as part of CXHO project.

[6] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same mercury emission factors.

[7] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.4. Emission Factors for Beryllium Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	H-2	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	H-3	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
11C PS											
Cont	H-200	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	H-300	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Coker											
SD	H-101[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-102[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-103[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-104[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
New Coker (#2 Coker)											
New	H-201					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	H-202					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	H-203					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
12PS											
SD	H-1AN[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-1AS[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-1B[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-2[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-1CN[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-1CX[5]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
New	H-101A					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	H-102					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	H-101B					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
Hydroprocessing											
3UF											
SD	H-1[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	H-2[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	F-7[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
4UF											
Oth	F-1	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-8A	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-8B	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-2	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-3	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-4	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-5	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-6	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-7	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
ARU											
Oth	F-200A	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-200B	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
BOU											
Mod	F-401	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
CFHU											
Oth	F-801A	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-801B	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-801C	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
GOHT											
New	F-901A					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	F-901B					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
CRU											
Oth	F-101	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	F-102	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
DDU											
Oth	WB-301	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
Oth	WB-302	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
DHT											
New	B-601A					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
ISOM											
Mod	H-1	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
HU											
Oth	B-501	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]	1.18E-08	1.18E-08
New HU (3rd Party SMR)											
New	HU-1[6]					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	HU-2[6]					1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]		1.18E-08
Utilities											
1SPS											
SD	Boiler 3[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	Boiler 4[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	Boiler 5[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	Boiler 6[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	Boiler 7[4]	1.20E-05	lb/10[6] scf	AP-42[1]	EF E Rating[2]					1.18E-08	
Fluidized Catalytic Cracking											
Oth	FCU 500	3.51E-06	lb/1000 lb coke burned	Industry Paper[3]		3.51E-06	lb/1000 lb coke burned	Industry Paper[3]		N/A	N/A
Mod[7]	FCU 600	3.51E-06	lb/1000 lb coke burned	Industry Paper[3]		3.51E-06	lb/1000 lb coke burned	Industry Paper[3]		N/A	N/A

Table C.4. Emission Factors for Beryllium Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[5]	1.20E-05	lb/10^6 scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	Beavon-Stretford Tail Gas Unit[5]	1.20E-05	lb/10^6 scf	AP-42[1]	EF E Rating[2]					1.18E-08	
SD	SRU Incinerator[5]	1.20E-05	lb/10^6 scf	AP-42[1]	EF E Rating[2]					1.18E-08	
New	New COT 1					1.20E-05	lb/10^6 scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	New COT 2					1.20E-05	lb/10^6 scf	AP-42[1]	EF E Rating[2]		1.18E-08
New Flares											
New	GOHT Flare: Pilot					1.20E-05	lb/10^6 scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	GOHT Flare: Purge					1.20E-05	lb/10^6 scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	South Flare: Pilot					1.20E-05	lb/10^6 scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	South Flare: Purge					1.20E-05	lb/10^6 scf	AP-42[1]	EF E Rating[2]		1.18E-08
New	HU Flare: Pilot					1.20E-05	lb/10^6 scf	AP-42[1]	EF E Rating[2]		1.18E-08
Lakefront											
SD	FBI (99-01)	1.64E-06	lb/ton feed								
SD	FBI(2003)	5.73E-06	lb/Mgal feed								
SD	FBI (02, 04 - 06)	8.22E-06	lb/Mgal feed								

Emission Factor Source References

[1] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4 "Natural Gas Combustion," Table 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION; (July 1998).

Justification References

[2] The Beryllium emission factors from AP-42 are used in the refinery industry as a standard when site specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.

[3] R. Bertrand and J. Siegell. Emission of Trace Compounds from Catalytic Cracking Regenerators, Environmental Progress (volume 21, No. 3). October 2002. Pages 163-167

Footnotes

[4] Existing unit being shutdown within the CXHO project contemporaneous period.

[5] Existing unit being shutdown as part of CXHO project.

[6] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same beryllium emission factors.

[7] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.5. Emission Factors for Nitrogen Oxides Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	0.166	lb/10[6] Btu	Stack Test[1]	Source Specific[12]	0.166	lb/10[6] Btu	Stack Test[1]	Source Specific[12]	0.166	0.166
Oth	H-2	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	0.098	0.098
Oth	H-3	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	0.098	0.098
11C PS											
Cont	H-200[21]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	0.05	lb/10[6] Btu	Design[10]	Guarantee[16]	0.275	0.05
Oth	H-300	0.137	lb/10[6] Btu	Stack Test[1]	Source Specific[12]	0.137	lb/10[6] Btu	Stack Test[1]	Source Specific[12]	0.137	0.137
Coker											
SD	H-101[18]	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]					0.098	
SD	H-102[18]	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]					0.098	
SD	H-103[18]	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]					0.098	
SD	H-104[18]	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]					0.098	
New Coker (#2 Coker)											
New	H-201					0.02	lb/10[6] Btu	Design[10]	Guarantee[16]		0.02
New	H-202					0.02	lb/10[6] Btu	Design[10]	Guarantee[16]		0.02
New	H-203					0.02	lb/10[6] Btu	Design[10]	Guarantee[16]		0.02
12PS											
SD	H-1AN[18]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]					0.275	
SD	H-1AS[18]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]					0.275	
SD	H-1B[18]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]					0.275	
SD	H-2[18]	0.036	lb/10[6] Btu	Stack Test[3]	Source Specific[12]					0.036	
SD	H-1CN[18]	100	lb/10[6] scf	AP-42[2]	EF A Rating[13]					0.098	
SD	H-1CX[18]	0.099	lb/10[6] Btu	Stack Test[1]	Source Specific[12]					0.099	
New	H-101A					0.05	lb/10[6] Btu	Design[10]	Guarantee[16]		0.050
New	H-102					0.05	lb/10[6] Btu	Design[10]	Guarantee[16]		0.050
New	H-101B					0.05	lb/10[6] Btu	Design[10]	Guarantee[16]		0.050
Hydroprocessing											
3UF											
SD	H-1[17]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]					0.275	
SD	H-2[17]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]					0.275	
SD	F-7[17]	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]					0.098	
4UF											
Oth	F-1	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	0.098	0.098
Oth	F-8A	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	0.275	0.275
Oth	F-8B	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	0.275	0.275
Oth	F-2	190	lb/10[6] scf	AP-42[2]	EF A Rating[13]	190	lb/10[6] scf	AP-42[2]	EF A Rating[13]	0.186	0.186
Oth	F-3	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	0.275	0.275
Oth	F-4	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	0.275	0.275
Oth	F-5	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	0.098	0.098
Oth	F-6	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	0.098	0.098
Oth	F-7	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	0.098	0.098
ARU											
Oth	F-200A	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	0.275	0.275
Oth	F-200B	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	0.275	0.275
BOU											
Mod	F-401	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	100	lb/10[6] scf	AP-42[2]	EF B Rating[13]	0.098	0.098
CFHU											
Oth	F-801A	50	lb/10[6] scf	AP-42[2]	EF D Rating[13]	50	lb/10[6] scf	AP-42[2]	EF D Rating[13]	0.049	0.049
Oth	F-801B	50	lb/10[6] scf	AP-42[2]	EF D Rating[13]	50	lb/10[6] scf	AP-42[2]	EF D Rating[13]	0.049	0.049
Oth	F-801C	0.036	lb/10[6] Btu	Stack Test[4]	Source Specific[12]	0.036	lb/10[6] Btu	Stack Test[4]	Source Specific[12]	0.036	0.036
GOHT											
New	F-901A					0.04	lb/10[6] Btu	Design[10]	Guarantee[16]		0.04
New	F-901B					0.04	lb/10[6] Btu	Design[10]	Guarantee[16]		0.04
CRU											
Oth	F-101	0.080	lb/10[6] Btu	Permit Limit[5]	Permit Limit[14]	0.080	lb/10[6] Btu	Permit Limit[5]	Permit Limit[14]	0.080	0.080
Oth	F-102	0.080	lb/10[6] Btu	Permit Limit[5]	Permit Limit[14]	0.080	lb/10[6] Btu	Permit Limit[5]	Permit Limit[14]	0.080	0.080
DDU											
Oth	WB-301	0.035	lb/10[6] Btu	Stack Test[1]	Source Specific[12]	0.035	lb/10[6] Btu	Stack Test[1]	Source Specific[12]	0.035	0.035
Oth	WB-302	0.030	lb/10[6] Btu	Stack Test[6]	Source Specific[12]	0.030	lb/10[6] Btu	Stack Test[6]	Source Specific[12]	0.030	0.030
DHT											
New	B-601A					0.04	lb/10[6] Btu	Design[10]	Guarantee[16]		0.040
ISOM											
Mod	H-1	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	280	lb/10[6] scf	AP-42[2]	EF A Rating[13]	0.275	0.275
HU											
Oth	B-501	0.068	lb/10[6] Btu	Stack Test[1]	Source Specific[12]	0.068	lb/10[6] Btu	Stack Test[1]	Source Specific[12]	0.068	0.068
New HU (3rd Party SMR)											
New	HU-1[19]					0.013	lb/10[6] Btu	Design[10]	Guarantee[16]		0.013
New	HU-2[19]					0.013	lb/10[6] Btu	Design[10]	Guarantee[16]		0.013
Utilities											
1SPS											
SD	Boiler 3[17]	0.157	lb/10[6] Btu	Stack Test[7]	Source Specific[12]					0.157	
SD	Boiler 4[17]	0.157	lb/10[6] Btu	Stack Test[7]	Source Specific[12]					0.157	
SD	Boiler 5[17]	0.093	lb/10[6] Btu	Stack Test[7]	Source Specific[12]					0.093	
SD	Boiler 6[17]	0.093	lb/10[6] Btu	Stack Test[7]	Source Specific[12]					0.093	
SD	Boiler 7[17]	0.093	lb/10[6] Btu	Stack Test[7]	Source Specific[12]					0.093	
Fluidized Catalytic Cracking											
Oth	FCU 500	40	ppm	Consent Decree[8]	Compliance with Consent Decree[15]	40	ppm	Consent Decree[8]	Compliance with Consent Decree[15]	N/A	N/A
Mod[21]	FCU 600	20	ppm	Consent Decree[9]	Compliance with Consent Decree[15]	20	ppm	Consent Decree[9]	Compliance with Consent Decree[15]	N/A	N/A

Table C.5. Emission Factors for Nitrogen Oxides Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[18]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]					0.098	
SD	Beavon-Stretford Tail Gas Unit[18]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]					0.098	
SD	SRU Incinerator[18]	100	lb/10^6 scf	AP-42[2]	EF B Rating[13]					0.098	
New	New COT 1					0.08	lb/10^6 Btu	Design[10]	Guarantee[16]		0.08
New	New COT 2					0.08	lb/10^6 Btu	Design[10]	Guarantee[16]		0.08
New Flares											
New	GOHT Flare: Pilot					100	lb/10^6 scf	AP-42[2]	EF B Rating[13]		0.098
New	GOHT Flare: Purge					0.068	lb/10^6 Btu	AP-42[11]	EF B Rating[13]		0.068
New	South Flare: Pilot					100	lb/10^6 scf	AP-42[2]	EF B Rating[13]		0.098
New	South Flare: Purge					0.068	lb/10^6 Btu	AP-42[11]	EF B Rating[13]		0.068
New	HU Flare: Pilot					100	lb/10^6 scf	AP-42[2]	EF B Rating[13]		0.098
Lakefront											
SD	FBI (99-01)	0.14	lb/unit feed	Source testing						N/A	
SD	FBI (02-06)	4.76	lb/Mgal FBI feed	Source testing						N/A	

Emission Factor Source References

[1] Based on stack test performed for BP Whiting Refinery.

[2] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4 "Natural Gas Combustion," Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NOx) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION SMALL BOILERS; (July 1998).

[3] Based on stack test performed for BP Whiting Refinery in March 2002.

[4] Based on stack test performed for BP Whiting Refinery in September 2003.

[5] Based on Permit Limit.

[6] Based on stack test performed for BP Whiting Refinery in January 2004.

[7] Based on stack test performed for BP Whiting Refinery in March 1993.

[8] NOx concentration limit from Consent Decree 4th Amendment, page 8 (United States, et.al v. BP Exploration & Oil, et. Al. Northern District of Indiana, Hammond Division Civil Action No. 2:96 CV 095 RL).

[9] NOx concentration limit from Consent Decree 4th Amendment, page 4 (United States, et.al v. BP Exploration & Oil, et. Al. Northern District of Indiana, Hammond Division Civil Action No. 2:96 CV 095 RL).

[10] Based on design requirement.

[11] U.S. AP-42. EPA. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.5, "Industrial Flares" Table 13.5-1. EMISSION FACTORS FOR FLARE OPERATION; (September 1991).

Justification References

[12] Based on most current source specific data.

[13] The Nitrogen Oxides (NOx) emission factors from AP-42 are used in the refinery industry as a standard when source specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.

[14] Emission factor based on emission limit in Draft Title V operating permit.

[15] Future emissions are assumed to be in compliance with Consent Decree. Baseline emissions were corrected to Consent Decree levels.

[16] Based on anticipated vendor guarantee to satisfy design requirement.

Emission Factor Source References

[17] Existing unit being shutdown within the CXHO project contemporaneous period.

[18] Existing unit being shutdown as part of CXHO project.

[19] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same NOX emission factors.

[20] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

[21] As part of the CXHO project, BP Whiting will be installing Ultra-Low NO_x burners on heater 11C PS H-200 to generate creditable emission reductions.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.6. Emission Factors for PM (Filterable) Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	H-2	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	H-3	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
11C PS											
Cont	H-200	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	H-300	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Coker											
SD	H-101[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-102[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-103[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-104[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
New Coker (#2 Coker)											
New	H-201					1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]		0.0019
New	H-202					1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]		0.0019
New	H-203					1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]		0.0019
12PS											
SD	H-1AN[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-1AS[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-1B[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-2[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-1CN[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-1CX[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
New	H-101A					1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]		0.0019
New	H-102					1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]		0.0019
New	H-101B					1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]		0.0019
Hydroprocessing											
3UF											
SD	H-1[10]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	H-2[10]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	F-7[10]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
4UF											
Oth	F-1	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-8A	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-8B	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-2	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-3	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-4	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-5	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-6	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-7	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
ARU											
Oth	F-200A	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-200B	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
BOU											
Mod	F-401	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
CFHU											
Oth	F-801A	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-801B	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-801C	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
GOHT											
New	F-901A					1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]		0.0019
New	F-901B					1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]		0.0019
CRU											
Oth	F-101	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	F-102	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
DDU											
Oth	WB-301	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
Oth	WB-302	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
DHT											
New	B-601A					1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]		0.0019
ISOM											
Mod	H-1	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
HU											
Oth	B-501	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]	0.0019	0.0019
New HU (3rd Party SMR)											
New	HU-1[12]					0.0068	lb/10[6] Btu	Design[5]	Guarantee[9]		0.0068
New	HU-2[12]					0.0068	lb/10[6] Btu	Design[5]	Guarantee[9]		0.0068
Utilities											
1SPS											
SD	Boiler 3[10]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	Boiler 4[10]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	Boiler 5[10]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	Boiler 6[10]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	Boiler 7[10]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
Fluidized Catalytic Cracking											
Oth	FCU 500	0.465	lb/10[3] lb coke burned	Stack Test[2]	Source Specific[9]	0.465	lb/10[3] lb coke burned	Stack Test[2]	Source Specific[9]	N/A	N/A
Mod[14]	FCU 600	0.35	lb/10[3] lb coke burned	Stack Test[2]	Source Specific[9]	0.35	lb/10[3] lb coke burned	Stack Test[2]	Source Specific[9]	N/A	N/A
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	Beavon-Stretford Tail Gas Unit[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
SD	SRU Incinerator[11]	1.9	lb/10[6] scf	AP-42[1]	EF B Rating[7]					0.0019	
New	New COT 1					1.9	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0019
New	New COT 2					1.9	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0019

Table C.6. Emission Factors for PM (Filterable) Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Cooling Towers											
Cont	Cooling Tower 2[13]	0.02%	liquid drift	AP-42[3]	EF E Rating[7]	0.001%	liquid drift	Design[4]	Guarantee[8]	N/A	N/A
		0.001%	liquid drift	Design[4]	Guarantee[8]	0.001%	liquid drift	Design[4]	Guarantee[8]	N/A	N/A
Cont	Cooling Tower 3	0.02%	liquid drift	AP-42[3]	EF E Rating[7]	0.001%	liquid drift	Design[4]	Guarantee[8]	N/A	N/A
Cont	Cooling Tower 4	0.02%	liquid drift	AP-42[3]	EF E Rating[7]	0.001%	liquid drift	Design[4]	Guarantee[8]	N/A	N/A
SD	SBS Cooling Tower[11]	0.02%	liquid drift	AP-42[3]	EF E Rating[7]					N/A	
New Cooling Towers											
New	Cooling Tower 7					0.001%	liquid drift	Design[5]	Guarantee[8]		N/A
New	Cooling Tower 8					0.001%	liquid drift	Design[5]	Guarantee[8]		N/A
New	HU Cooling Tower					0.001%	liquid drift	Design[5]	Guarantee[8]		N/A
New Flares											
New	GOHT Flare: Pilot					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	GOHT Flare: Purge					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	South Flare: Pilot					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	South Flare: Purge					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
New	HU Flare: Pilot					1.9	lb/10^6 scf	AP-42[1]	EF B Rating[7]		0.0019
Fugitive Dust											
New	Transfer Point 1, 10					0.000880	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
New	Transfer Point 2 - 9					0.000880	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
New	Transfer Point 1,2,3 AOS					0.000880	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
New	Transfer Point 4 AOS					0.000880	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
SD	Aggregate Storage - Pile	0.49	lb/hr/acre	1988 EPA Report[6.1]						N/A	
SD	Aggregate Storage - Coke Yard	1.12	lb/hr/acre	1988 EPA Report[6.1]						N/A	
SD	Aggregate Handling	0.000645	lb/ton handled/transfer point	AP-42[6]	EF A Rating[7]					N/A	
SD	Paved Road Emissions	5.27	lb/VMT	AP-42[6.2]	EF A Rating[7]					N/A	
SD	Unpaved Road Emissions - Truck	7.70	lb/VMT	AP-42[6.3]	EF A Rating[7]					N/A	
SD	Unpaved Road Emissions - Front End Loader	10.23	lb/VMT	AP-42[6.3]	EF A Rating[7]					N/A	
Lakefront											
SD	FBI (99-01)	0.184	lb/unit feed	Source testing						N/A	
SD	FBI (02-06)	0.0255	lb/Mgal FBI feed	Source testing						N/A	

Emission Factor Source References

[1] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4 "Natural Gas Combustion," Table 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION; (July 1998).

[2] Based on stack test performed for BP Whiting Refinery in June 2005.

[3] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 13, Section 13.4, Wet Cooling Towers, Table 13.4-1 PARTICULATE EMISSION FACTORS FOR WET COOLING TOWERS; (January 1995).

[4] Based on material balance including average total dissolved solids and recirculation rates from 1999 to 2004 along with design requirements of drift eliminators.

[5] Based on design requirement.

[6] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.2.4 "Aggregate Handling and Storage Piles," Equation (1). (March 2006).

[6.1] Chapter 4 of the 1988 EPA Report "Control of Open Fugitive Dust Sources". (EPA - 450/3-88-008) Note Chapter 4 1988 EPA Report provides a method to calculate wind emissions from a continuously active pile. This is more representative of the aggregate storage at BP Whiting than the AP-42 Section 13.2.5 "Industrial Wind Erosion", which better represents discreet disturbances.

[6.2] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.2.1 "Paved Roads", Equation (1). (November 2006).

[6.2] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.2.2 "Unpaved Roads", Equation (1a). (November 2006).

Justification References

[7] The particulate matter (PM) emission factors from AP-42 are used in the refinery industry as a standard when site specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.
E - Poor - Developed from lower rated test data from a small number of facilities.

[8] Based on anticipated vendor guarantee to satisfy design requirement.

[9] Based on most current source specific data.

Emission Unit References

[10] Existing unit being shutdown within the CXHO project contemporaneous period.

[11] Existing unit being shutdown as part of CXHO project.

[12] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same particulate emission factors.

[13] Half of the Cooling Tower 2 modules were controlled by high efficiency drift eliminators in the baseline period.

[14] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.7. Emission Factors for PM_{10} and $PM_{2.5}$ (Filterable + Condensable) Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor[15]	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0075	0.0075
Oth	H-2	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0075	0.0075
Oth	H-3	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0075	0.0075
11C PS											
Cont	H-200	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0075	0.0075
Oth	H-300	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0075	0.0075
Coker											
SD	H-101[11]	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]					0.0040	
SD	H-102[11]	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]					0.0040	
SD	H-103[11]	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]					0.0040	
SD	H-104[11]	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]					0.0040	
New Coker (#2 Coker)											
New	H-201					7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0075
New	H-202					7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0075
New	H-203					7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0075
12PS											
SD	H-1AN[11]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	H-1AS[11]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	H-1B[11]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	H-2[11]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	H-1CN[11]	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]					0.0040	
SD	H-1CX[11]	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]					0.0040	
New	H-101A					7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0075
New	H-102					7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0075
New	H-101B					7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0075
Hydroprocessing											
3UF											
SD	H-1[10]	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]					0.0040	
SD	H-2[10]	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]					0.0040	
SD	F-7[10]	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]					0.0040	
4UF											
Oth	F-1	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-8A	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-8B	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-2	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-3	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-4	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-5	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-6	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-7	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
ARU											
Oth	F-200A	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-200B	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
BOU											
Mod	F-401	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
CFHU											
Oth	F-801A	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-801B	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-801C	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
GOHT											
New	F-901A					7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0075
New	F-901B					7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0075
CRU											
Oth	F-101	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	F-102	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
DDU											
Oth	WB-301	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
Oth	WB-302	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
DHT											
New	B-601A					7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0075
ISOM											
Mod	H-1	0.004	lb/10[6] Btu	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0040	0.0075
HU											
Oth	B-501	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]	0.0075	0.0075
New HU (3rd Party SMR)											
New	HU-1[12]					0.0068	lb/10[6] Btu	Design[5]	Guarantee[9]		0.0068
New	HU-2[12]					0.0068	lb/10[6] Btu	Design[5]	Guarantee[9]		0.0068
Utilities											
1SPS											
SD	Boiler 3[10]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	Boiler 4[10]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	Boiler 5[10]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	Boiler 6[10]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	Boiler 7[10]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]					0.0075	
Fluidized Catalytic Cracking											
Oth	FCU 500	0.465	lb/10[3] lb Coke Burned	Stack Test[2]	Source Specific[8]	0.465	lb/10[3] lb Coke Burned	Stack Test[2]	Source Specific[8]	N/A	N/A
Mod[14]	FCU 600	0.35	lb/10[3] lb Coke Burned	Stack Test[2]	Source Specific[8]	0.35	lb/10[3] lb Coke Burned	Stack Test[2]	Source Specific[8]	N/A	N/A
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[11]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	Beavon-Stretford Tail Gas Unit[11]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]					0.0075	
SD	SRU Incinerator[11]	7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]					0.0075	
New	New COT 1					7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0075
New	New COT 2					7.6	lb/10[6] scf	AP-42[1]	EF D Rating[7]		0.0075

Table C.7. Emission Factors for PM_{10} and $PM_{2.5}$ (Filterable + Condensable) Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor[15]	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Cooling Towers											
Cont	Cooling Tower 2[13]	0.02%	liquid drift	AP-42[3]	EF E Rating[7]	0.001%	liquid drift	Design[4]	Guarantee[8]	N/A	N/A
		0.001%	liquid drift	Design[4]	Guarantee[8]	0.001%	liquid drift	Design[4]	Guarantee[8]	N/A	N/A
Cont	Cooling Tower 3	0.02%	liquid drift	AP-42[3]	EF E Rating[7]	0.001%	liquid drift	Design[4]	Guarantee[9]	N/A	N/A
Cont	Cooling Tower 4	0.02%	liquid drift	AP-42[3]	EF E Rating[7]	0.001%	liquid drift	Design[4]	Guarantee[9]	N/A	N/A
SD	SBS Cooling Tower[11]	0.02%	liquid drift	AP-42[3]	EF E Rating[7]					N/A	
New Cooling Towers											
New	Cooling Tower 7					0.001%	liquid drift	Design[5]	Guarantee[9]		N/A
New	Cooling Tower 8					0.001%	liquid drift	Design[5]	Guarantee[9]		N/A
New	HU Cooling Tower					0.001%	liquid drift	Design[5]	Guarantee[9]		N/A
New Flares											
New	GOHT Flare: Pilot					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	GOHT Flare: Purge					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	South Flare: Pilot					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	South Flare: Purge					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
New	HU Flare: Pilot					7.6	lb/10^6 scf	AP-42[1]	EF D Rating[7]		0.0075
Fugitive Dust											
New	Transfer Point 1, 10					0.000416	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
New	Transfer Point 2 - 9					0.000416	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
New	Transfer Point 1,2,3 AOS					0.000416	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
New	Transfer Point 4 AOS					0.000416	lb/ton coke	AP-42[6]	EF A Rating[7]		N/A
SD	Aggregate Storage - Pile	0.24	lb/hr/acre	1988 EPA Report[6.1]						N/A	
SD	Aggregate Storage - Coke Yard	0.56	lb/hr/acre	1988 EPA Report[6.1]						N/A	
SD	Aggregate Handling	0.000305	lb/ton handled/transfer point	AP-42[6]	EF A Rating[7]					N/A	
SD	Paved Road Emissions	1.03	lb/VMT	AP-42[6.2]	EF A Rating[7]					N/A	
SD	Unpaved Road Emissions - Truck	2.29	lb/VMT	AP-42[6.3]	EF A Rating[7]					N/A	
SD	Unpaved Road Emissions - Front End Loader	3.04	lb/VMT	AP-42[6.3]	EF A Rating[7]					N/A	
Lakefront											
SD	FBI (99-01)	0.184	lb/unit feed	Source testing						N/A	
SD	FBI (02-06)	0.0255	lb/Mgal FBI feed	Source testing						N/A	

Emission Factor Source References

[1] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4 "Natural Gas Combustion," Table 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION; (July 1998).

[2] Based on stack test performed for BP Whiting Refinery in June 2005.

[3] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 13, Section 13.4, Wet Cooling Towers, Table 13.4-1 PARTICULATE EMISSION FACTORS FOR WET COOLING TOWERS; (January 1995).

[4] Based on material balance including average total dissolved solids and recirculation rates from 1999 to 2004 along with design requirements of drift eliminators.

[5] Based on design requirement.

[6] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.2.4 "Aggregate Handling and Storage Piles," Equation (1). (March 2006).

[6.1] Chapter 4 of the 1988 EPA Report "Control of Open Fugitive Dust Sources". (EPA - 450/3-88-008) Note Chapter 4 1988 EPA Report provides a method to calculate wind emissions from a continuously active pile. This is more representative of the aggregate storage at BP Whiting than the AP-42 Section 13.2.5 "Industrial Wind Erosion", which better represents discreet disturbances.

[6.2] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.2.1 "Paved Roads", Equation (1). (November 2006).

[6.2] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.2.2 "Unpaved Roads", Equation (1a). (November 2006).

Justification References

[7] The total particulate matter (PM) emission factors from AP-42 are used in the refinery industry as a standard when site specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.
E - Poor - Developed from lower rated test data from a small number of facilities.

[8] Based on anticipated vendor guarantee to satisfy design requirement.

[9] Based on most current source specific data.

Emission Unit References

[10] Existing unit being shutdown within the CXHO project contemporaneous period.

[11] Existing unit being shutdown as part of CXHO project.

[12] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same particulate emission factors.

[13] Half of the Cooling Tower 2 modules were controlled by high efficiency drift eliminators in the baseline period.

[14] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

[15] Based on interim guidance from US EPA, $PM_{2.5}$ is evaluated based on significant emission rate thresholds established for PM_{10}. The current PM_{10} SIP limits filterable PM_{10} emissions and compliance is based on reference test method 201A (which only quantifies filterable particulate matter). Although not required, BP Whiting has conservatively adjusted the PM_{10} baseline based on the PM_{10} SIP limits for PSD applicability purposes, which includes both filterable and condensable PM_{10}. $PM_{2.5}$ emissions are not regulated by the Lake County PM_{10} SIP, however, to be conservative, BP Whiting has adjusted $PM_{2.5}$ baseline emissions in the same manner as for PM_{10} emissions.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.8. Emission Factors for Sulfuric Acid Mist Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions			
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification
Crude and Coking									
11A PS									
Oth	H-1X	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	H-2	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	H-3	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
11C PS									
Cont	H-200	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	H-300	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Coker									
SD	H-101[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-102[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-103[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-104[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
New Coker (#2 Coker)									
New	H-201					See EF Reference[2]		CEMS[2]	Source Specific[4]
New	H-202					See EF Reference[2]		CEMS[2]	Source Specific[4]
New	H-203					See EF Reference[2]		CEMS[2]	Source Specific[4]
12PS									
SD	H-1AN[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-1AS[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-1B[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-2[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-1CN[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-1CX[6]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
New	H-101A					See EF Reference[2]		CEMS[2]	Source Specific[4]
New	H-102					See EF Reference[2]		CEMS[2]	Source Specific[4]
New	H-101B					See EF Reference[2]		CEMS[2]	Source Specific[4]
Hydroprocessing									
3UF									
SD	H-1[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	H-2[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	F-7[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
4UF									
Oth	F-1	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-8A	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-8B	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-2	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-3	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-4	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-5	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-6	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-7	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
ARU									
Oth	F-200A	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-200B	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
BOU									
Mod	F-401	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
CFHU									
Oth	F-801A	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-801B	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-801C	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
GOHT									
New	F-901A					See EF Reference[2]		CEMS[2]	Source Specific[4]
New	F-901B					See EF Reference[2]		CEMS[2]	Source Specific[4]
CRU									
Oth	F-101	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	F-102	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
DDU									
Oth	WB-301	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
Oth	WB-302	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
DHT									
New	B-601A					See EF Reference[2]		CEMS[2]	Source Specific[4]
ISOM									
Mod	H-1	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
HU									
Oth	B-501	See EF Reference[1]		CEMS[1]	Source Specific[3]	See EF Reference[2]		CEMS[2]	Source Specific[4]
New HU (3rd Party SMR)									
New	HU-1[7]					See EF Reference[2]		CEMS[2]	Source Specific[4]
New	HU-2[7]					See EF Reference[2]		CEMS[2]	Source Specific[4]

Table C.8. Emission Factors for Sulfuric Acid Mist Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions			
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification
Utilities									
1SPS									
SD	Boiler 3[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	Boiler 4[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	Boiler 5[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	Boiler 6[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
SD	Boiler 7[5]	See EF Reference[1]		CEMS[1]	Source Specific[3]				
Lakefront									
SD	FBI (99-01)	N/A							
SD	FBI (02-06)	N/A							

Emission Factor Source References

[1] Calculation based on sulfur dioxide (SO_2) emissions. SO_2 emissions were calculated using hydrogen sulfide (H_2S) CEMS data, and TRS testing data where available.

[2] Calculation based on future potential sulfur dioxide (SO_2) emissions. SO_2 emissions were calculated using the future design fuel gas total sulfur.

Justification References

[3] Based on baseline year source specific data (SO_2 emissions CEMS data).

[4] Based on future potential SO_2 emissions.

Emission Unit References

[5] Existing unit being shutdown within the CXHO project contemporaneous period.

[6] Existing unit being shutdown as part of CXHO project.

[7] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Only the combustion of natural gas will emit SO_2 and therefore sulfuric acid mist.

Calculation Methodology

Combustion emissions are assumed to include some amount of SO_3, which can react with water vapor present in the stack to produce sulfuric acid mist (H_2SO_4 mist) as shown in Equation C-8-1.

Equation C-8-1

$$SO_3 + H_2O \Leftrightarrow H_2SO_4$$

H_2SO_4 mist emissions are conservatively calculated by assuming 3% of the SO_X emitted by the heater is in the form of SO_3.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.9. Emission Factors for Sulfur Dioxide Emissions

		Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu			
Code	Process Unit	Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	2001	2002	Baseline	Future
Crude and Coking													
11A PS													
Oth	H-1X	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
Oth	H-2	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
Oth	H-3	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
11C PS													
Cont	H-200	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
Oth	H-300	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
Coker													
SD	H-101[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-102[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-103[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-104[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
New Coker (#2 Coker)													
New	H-201					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	H-202					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	H-203					80	ppm	CEMS[1]	Source Specific[10]				0.0111
12PS													
SD	H-1AN[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-1AS[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-1B[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-2[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-1CN[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	H-1CX[15]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
New	H-101A					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	H-102					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	H-101B					80	ppm	CEMS[1]	Source Specific[10]				0.0111
Hydroprocessing													
3UF													
SD	H-1[14]	42.12	ppm	CEMS[1]	Source Specific[8]					0.0113	0.0074	0.0094	
SD	H-2[14]	42.12	ppm	CEMS[1]	Source Specific[8]					0.0113	0.0074	0.0094	
SD	F-7[14]	42.12	ppm	CEMS[1]	Source Specific[8]					0.0113	0.0074	0.0094	
4UF													
Oth	F-1	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-8A	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-8B	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-2	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-3	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-4	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-5	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-6	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
Oth	F-7	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
ARU													
Oth	F-200A	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
Oth	F-200B	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
BOU													
Mod	F-401	47.01	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0086	0.0090	0.0088	0.0111
CFHU													
Oth	F-801A	48.43	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0074	0.0128	0.0101	0.0111
Oth	F-801B	48.43	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0074	0.0128	0.0101	0.0111
Oth	F-801C	48.43	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0074	0.0128	0.0101	0.0111
GOHT													
New	F-901A					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	F-901B					80	ppm	CEMS[1]	Source Specific[10]				0.0111
CRU													
Oth	F-101	42.12	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0113	0.0074	0.0094	0.0111
Oth	F-102	42.12	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0113	0.0074	0.0094	0.0111
DDU													
Oth	WB-301	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
Oth	WB-302	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
DHT													
New	B-601A					0.6	lb/10[6] scf	AP-42[6]	EF A Rating[12]				0.0006
ISOM													
Mod	H-1	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0217	0.0210	0.0213	0.0111
HU													
Oth	B-501	159.09	ppm	CEMS[1]	Source Specific[8]	80	ppm	CEMS[1]	Source Specific[10]	0.0703	0.0672	0.0687	0.0111
New HU (3rd Party SMR)													
New	HU-1[16]					0.6	lb/10[6] scf	AP-42[6]	EF A Rating[12]				0.0006
						0	ppm	Process Design[13a]					0.0000
New	HU-2[16]					0.6	lb/10[6] scf	AP-42[6]	EF A Rating[12]				0.0006
						0	ppm	Process Design[13a]					0.0000
Utilities													
1SPS													
SD	Boiler 3[14]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	Boiler 4[14]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	Boiler 5[14]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	Boiler 6[14]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
SD	Boiler 7[14]	159.09	ppm	CEMS[1]	Source Specific[8]					0.0217	0.0210	0.0213	
Fluidized Catalytic Cracking													
Oth	FCU 500	25	ppm	Consent Decree[2]	Compliance with Consent Decree[9]	25	ppm	CEMS[5]	Source Specific[11]	N/A	N/A	N/A	N/A
Mod[17]	FCU 600	50	ppm	Consent Decree[3]	Compliance with Consent Decree[9]	37	ppm	CEMS[5]	Source Specific[11]	N/A	N/A	N/A	N/A

Table C.9. Emission Factors for Sulfur Dioxide Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu			
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	2001	2002	Baseline	Future
Sulfur Recovery Complex													
SD	SBS Tail Gas Unit[15]	0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]					0.0006	0.0006	0.0006	
SD	Beavon-Stretford Tail Gas Unit[15]	0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]					0.0006	0.0006	0.0006	
SD	SRU Incinerator[11]	0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]					0.0006	0.0006	0.0006	
New	New COT 1												
	Thermal Oxidizer					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
	Process					45	ppm	Design[7]	Guarantee[13]				N/A
New	New COT 2												
	Thermal Oxidizer					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
	Process					45	ppm	Design[7]	Guarantee[13]				N/A
New Flares													
New	GOHT Flare: Pilot					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
New	GOHT Flare: Purge					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	South Flare: Pilot					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
New	South Flare: Purge					80	ppm	CEMS[1]	Source Specific[10]				0.0111
New	HU Flare: Pilot					0.6	lb/10^6 scf	AP-42[6]	EF A Rating[12]				0.0006
Lakefront													
SD	FBI (99-01)	0.13	lb/unit feed	Source testing						N/A	N/A	N/A	
SD	FBI (02-06)	0.0093	lb/Mgal FBI feed	Source testing						N/A	N/A	N/A	

Emission Factor Source References

[1] Baseline actual emissions calculated using Hydrogen sulfide (H_2S) CEMS data and TRS sampling. Future actual emissions based on CXHO design for total sulfur in the fuel gas.

[2] Sulfur dioxide (SO_2) concentration limit from Consent Decree 4th Amendment, page 9 (United States, et.al v. BP Exploration & Oil, et. al. Northern District of Indiana, Hammond Division Civil Action No. 2:96 CV 095 RL).

[3] SO_2 concentration limit from Consent Decree 4th Amendment, page 11 (United States, et.al v. BP Exploration & Oil, et. al. Northern District of Indiana, Hammond Division Civil Action No. 2:96 CV 095 RL).

[4] Baseline actual emissions calculated using H_2S and remaining Total Reduce Sulfur (TRS) CEMS data.

[5] Future SO_2 ppm based on anticipated operation to achieve future projected emission rate.

[6] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4 "Natural Gas Combustion," Table 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION; (July 1998).

[7] Based on design requirement.

Justification References

[8] Based on source specific data.

[9] Baseline emissions were corrected to Consent Decree levels.

[10] Based on future projected total sulfur in the fuel gas.

[11] Future projected emissions based on anticipated operation of FCU 500 and 600. 20 ppm concentration is the basis for the proposed tpy limit.

[12] The sulfur dioxide (SO2) emission factors from AP-42 are used in the refinery industry as a standard when site specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:

A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.
E - Poor - Developed from lower rated test data from a small number of facilities.

[13] Based on anticipated vendor guarantee to satisfy design requirement.

[13a] Inherent to the process design, the pressure swing adsorption (PSA) offgas does not contain any sulfur compounds.

Emission Unit References

[14] Existing unit being shutdown within the CXHO project contemporaneous period.

[15] Existing unit being shutdown as part of CXHO project.

[16] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Only combustion of natural gas produces SO_2 emissions.

[17] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.10. Emission Factors for Volatile Organic Compound Emissions

Code	Process Unit	Baseline Actual Emissions				Future Potential Emissions				Emission Factors in lb/MMBtu	
		Emission Factor	Unit	Source	Justification	Emission Factor	Unit	Source	Justification	Baseline	Future
Crude and Coking											
11A PS											
Oth	H-1X	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	H-2	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	H-3	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
11C PS											
Cont	H-200	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	H-300	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Coker											
SD	H-101[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-102[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-103[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-104[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
New Coker (#2 Coker)											
New	H-201					5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]		0.0054
New	H-202					5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]		0.0054
New	H-203					5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]		0.0054
12PS											
SD	H-1AN[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-1AS[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-1B[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-2[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-1CN[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-1CX[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
New	H-101A					5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]		0.0054
New	H-102					5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]		0.0054
New	H-101B					5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]		0.0054
Hydroprocessing											
3UF											
SD	H-1[10]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	H-2[10]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	F-7[10]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
4UF											
Oth	F-1	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-8A	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-8B	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-2	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-3	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-4	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-5	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-6	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-7	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
ARU											
Oth	F-200A	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-200B	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
BOU											
Mod	F-401	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
CFHU											
Oth	F-801A	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-801B	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-801C	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
GOHT											
New	F-901A					5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]		0.0054
New	F-901B					5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]		0.0054
CRU											
Oth	F-101	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	F-102	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
DDU											
Oth	WB-301	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
Oth	WB-302	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
DHT											
New	B-601A					5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]		0.0054
ISOM											
Mod	H-1	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
HU											
Oth	B-501	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[6]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]	0.0054	0.0054
New HU (3rd Party SMR)											
New	HU-1[12]					0.0034	lb/10[6] Btu	Design[6]	Guarantee[9]		0.0034
New	HU-2[12]					0.0034	lb/106 Btu	Design[6]	Guarantee[9]		0.0034
Utilities											
1SPS											
SD	Boiler 3[10]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	Boiler 4[10]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	Boiler 5[10]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	Boiler 6[10]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	Boiler 7[10]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
Fluidized Catalytic Cracking											
Oth	FCU 500	220	lb/10[3] bbl of fresh feed	AP-42[2]	EF B Rating[7]	220	lb/10[3] bbl of fresh feed	AP-42[2]	EF B Rating[7]	N/A	N/A
Mod[14]	FCU 600	220	lb/10[3] bbl of fresh feed	AP-42[2]	EF B Rating[7]	220	lb/10[3] bbl of fresh feed	AP-42[2]	EF B Rating[7]	N/A	N/A
Sulfur Recovery Complex											
SD	SBS Tail Gas Unit[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	Beavon-Stretford Tail Gas Unit[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
SD	SRU Incinerator[11]	5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]					0.0054	
New	New COT 1					5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]		0.0054
New	New COT 2					5.5	lb/10[6] scf	AP-42[1]	EF C Rating[7]		0.0054

Table C.10. Emission Factors for Volatile Organic Compound Emissions

Cooling Tower											
SD	SBS Cooling Tower	0.7	lb/10^6 gal cooling water	AP-42[3]	EF D Rating[7]					N/A	
New Cooling Towers											
New	Cooling Tower 7					0.7	lb/10^6 gal cooling water	AP-42[3]	EF D Rating[7]		N/A
New	Cooling Tower 8					0.7	lb/10^6 gal cooling water	AP-42[3]	EF D Rating[7]		N/A
New	HU Cooling Tower[13]										
New Flares											
New	GOHT Flare: Pilot					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
New	GOHT Flare: Purge					0.14	lb/10^6 Btu	AP-42[5]	EF B Rating[7]		0.1400
New	South Flare: Pilot					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
New	South Flare: Purge					0.14	lb/10^6 Btu	AP-42[5]	EF B Rating[7]		0.1400
New	HU Flare: Pilot					5.5	lb/10^6 scf	AP-42[1]	EF C Rating[7]		0.0054
Marine Loading											
Cont	Gasoline Loading	See EF Reference[4]		AP-42[4]	Source Specific[8]	10	mg/L	Design[6]	Guarantee[9]	N/A	N/A
Lakefront											
SD	FBI (99-01)	0.34	lb/unit feed	Source testing						N/A	
SD	FBI (02-04)	0.0025	lb/Mgal WW	Source testing						N/A	
SD	FBI (02-06)	0.0305	lb/ton waste fed to FBI	Source testing						N/A	

Emission Factor Source References

[1] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 1.4, "Natural Gas Combustion," Table 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION; (July 1998).

[2] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 5, Section 5.1, "Petroleum Refining," Table 5.1-1. EMISSIONS FOR PETROLEUM REFINERIES; (July 1995).

[3] U.S. EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 5, Section 5.1, "Petroleum Refining," Table 5.1-2 FUGITIVE EMISSION FACTORS FOR PETROLEUM REFINING; (July 1995).

[4] U.S.EPA. AP-42. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 5, Section 5.2, Transportation and Marketing of Petroleum Liquid, Equation (1) and Table 5.2-1. SATURATION FACTOR FOR CALCULATING PETROLEUM LIQUID LOADING LOSS; (January 1995). Emission factor calculated using saturation factor, true vapor pressure, molecular weight, and temperature. See Tables C.45-47 for more details.

[5] U.S. AP-42. EPA. Fifth Edition. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 1, Section 13.5, Industrial Flares Table 13.5-1. EMISSION FACTORS FOR FLARE OPERATION; (September 1991).

[6] Based on design requirement.

Justification Reference

[7] The Volatile Organic Compound (VOC) emission factors from AP-42 are used in the refinery industry as a standard when site specific data is not available. Each AP-42 emission factor has a quality rating which indicates the quality of the test(s) used to develop the factor. The ratings are as follows:
A - Excellent - Developed only from the highest rated test data taken from many randomly chosen facilities in the industry population.
B - Above Average - Developed from the highest rated test data from a reasonable number of facilities.
C - Average - Developed from highly rated test data from a reasonable number of facilities.
D - Below Average - Developed from highly rated test data from a small number of facilities.

[8] Based on source specific vapor pressure, temperature, and molecular weight.

[9] Based on anticipated vendor guarantee to satisfy design requirement.

Emission Unit References

[10] Existing unit being shutdown within the CXHO project contemporaneous period.

[11] Existing unit being shutdown as part of CXHO project.

[12] The new hydrogen unit heaters HU-1 and HU-2 will burn both natural gas and PSA tail gas. Both fuel sources are conservatively assumed to have the same VOC emission factors.

[13] The new hydrogen unit cooling tower will be operated separately from refinery operations. VOC emissions are only applicable to cooling towers serving petroleum refinery operations.

[14] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Codes

New	New Unit
Mod	Modified Unit
Cont	Controlled*
Oth	Other Unit
SD	Shutdown

* Emissions are being reduced for at least one pollutant.

Table C.11. Project Combustion Emissions

Process Heaters and Boilers

Code	Process Unit	Capacity/Usage				VOC				NO_x				SO_2						PM(Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensable)						CO				Pb				H_2SO_4 Mist		Hg				Be			
						EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	EF	Unit	lb/hr[1]	tpy[2]	EF	Unit	lb/hr[1]	tpy	EF	Unit	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
Crude and Coking																																															
11A PS																																															
Oth	H-1X	173.9	MMBtu/hr	1,523,364	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.1	0.166	lb/MMBtu	28.9	126.4	13.30	lb/MMscf	0.0111	lb/MMBtu	1.9	8.4	0.0019	lb/MMBtu	0.3	1.4	7.6	lb/MMscf	0.0075	lb/MMBtu	1.3	5.7	0.082	lb/MMBtu	14.3	62.7	4.90E-07	lb/MMBtu	8.5E-05	3.7E-04	0.09	0.39	1.80E-07	lb/MMBtu	3.1E-05	1.4E-04	1.18E-08	lb/MMBtu	2.0E-06	9.0E-06
Oth	H-2	32.3	MMBtu/hr	282,948	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.098	lb/MMBtu	3.2	13.9	13.30	lb/MMscf	0.0111	lb/MMBtu	0.4	1.6	0.0019	lb/MMBtu	0.1	0.3	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	1.1	0.082	lb/MMBtu	2.7	11.7	4.90E-07	lb/MMBtu	1.6E-05	6.9E-05	0.02	0.07	1.80E-07	lb/MMBtu	5.8E-06	2.5E-05	1.18E-08	lb/MMBtu	3.8E-07	1.7E-06
Oth	H-3	49.2	MMBtu/hr	430,992	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.098	lb/MMBtu	4.8	21.1	13.30	lb/MMscf	0.0111	lb/MMBtu	0.5	2.4	0.0019	lb/MMBtu	0.1	0.4	7.6	lb/MMscf	0.0075	lb/MMBtu	0.4	1.6	0.082	lb/MMBtu	4.1	17.7	4.90E-07	lb/MMBtu	2.4E-05	1.1E-04	0.02	0.11	1.80E-07	lb/MMBtu	8.9E-06	3.9E-05	1.18E-08	lb/MMBtu	5.8E-07	2.5E-06
11C PS																																															
Cont	H-200	182.8	MMBtu/hr	1,601,328	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.3	0.05	lb/MMBtu	9.1	40.0	13.30	lb/MMscf	0.0111	lb/MMBtu	2.0	8.9	0.0019	lb/MMBtu	0.3	1.5	7.6	lb/MMscf	0.0075	lb/MMBtu	1.4	6.0	0.082	lb/MMBtu	15.1	65.9	4.90E-07	lb/MMBtu	9.0E-05	3.9E-04	0.09	0.41	1.80E-07	lb/MMBtu	3.3E-05	1.4E-04	1.18E-08	lb/MMBtu	2.2E-06	9.4E-06
Oth	H-300	72.0	MMBtu/hr	630,720	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.137	lb/MMBtu	9.9	43.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.8	3.5	0.0019	lb/MMBtu	0.1	0.6	7.6	lb/MMscf	0.0075	lb/MMBtu	0.5	2.3	0.082	lb/MMBtu	5.9	26.0	4.90E-07	lb/MMBtu	3.5E-05	1.5E-04	0.04	0.16	1.80E-07	lb/MMBtu	1.3E-05	5.7E-05	1.18E-08	lb/MMBtu	8.5E-07	3.7E-06
Coker																																															
SD	H-101	0.0	MMBtu/hr	0	MMBtu/yr																																										
SD	H-102	0.0	MMBtu/hr	0	MMBtu/yr																																										
SD	H-103	0.0	MMBtu/hr	0	MMBtu/yr																																										
SD	H-104	0.0	MMBtu/hr	0	MMBtu/yr																																										
New Coker (#2 Coker)																																															
New	H-201	208.0	MMBtu/hr	1,822,080	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.9	0.02	lb/MMBtu	4.2	18.2	13.30	lb/MMscf	0.0111	lb/MMBtu	2.3	10.1	0.0019	lb/MMBtu	0.5	2.3	7.6	lb/MMscf	0.0075	lb/MMBtu	1.7	7.4	0.019	lb/MMBtu	4.0	17.3	4.90E-07	lb/MMBtu	1.0E-04	4.5E-04	0.11	0.46	1.80E-07	lb/MMBtu	3.7E-05	1.6E-04	1.18E-08	lb/MMBtu	2.4E-06	1.1E-05
New	H-202	208.0	MMBtu/hr	1,822,080	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.9	0.02	lb/MMBtu	4.2	18.2	13.30	lb/MMscf	0.0111	lb/MMBtu	2.3	10.1	0.0019	lb/MMBtu	0.5	2.3	7.6	lb/MMscf	0.0075	lb/MMBtu	1.7	7.4	0.019	lb/MMBtu	4.0	17.3	4.90E-07	lb/MMBtu	1.0E-04	4.5E-04	0.11	0.46	1.80E-07	lb/MMBtu	3.7E-05	1.6E-04	1.18E-08	lb/MMBtu	2.4E-06	1.1E-05
New	H-203	208.0	MMBtu/hr	1,822,080	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.9	0.02	lb/MMBtu	4.2	18.2	13.30	lb/MMscf	0.0111	lb/MMBtu	2.3	10.1	0.0019	lb/MMBtu	0.5	2.3	7.6	lb/MMscf	0.0075	lb/MMBtu	1.7	7.4	0.019	lb/MMBtu	4.0	17.3	4.90E-07	lb/MMBtu	1.0E-04	4.5E-04	0.11	0.46	1.80E-07	lb/MMBtu	3.7E-05	1.6E-04	1.18E-08	lb/MMBtu	2.4E-06	1.1E-05
12PS																																															
SD	H-1AN	0.0	MMBtu/hr	0	MMBtu/yr																																										
SD	H-1AS	0.0	MMBtu/hr	0	MMBtu/yr																																										
SD	H-1B	0.0	MMBtu/hr	0	MMBtu/yr																																										
SD	H-1CN	0.0	MMBtu/hr	0	MMBtu/yr																																										
SD	H-1CX	0.0	MMBtu/hr	0	MMBtu/yr																																										
SD	H-2	0.0	MMBtu/hr	0	MMBtu/yr																																										
New	H-101A	355.0	MMBtu/hr	3,109,800	MMBtu/yr	0.0054	lb/MMBtu	1.9	8.4	0.05	lb/MMBtu	17.8	77.7	13.30	lb/MMscf	0.0111	lb/MMBtu	3.9	17.2	0.0019	lb/MMBtu	0.7	2.9	7.6	lb/MMscf	0.0075	lb/MMBtu	2.6	11.6	0.019	lb/MMBtu	6.7	29.5	4.90E-07	lb/MMBtu	1.7E-04	7.6E-04	0.18	0.79	1.80E-07	lb/MMBtu	6.4E-05	2.8E-04	1.18E-08	lb/MMBtu	4.2E-06	1.8E-05
New	H-102	331.0	MMBtu/hr	2,899,560	MMBtu/yr	0.0054	lb/MMBtu	1.8	7.8	0.05	lb/MMBtu	16.6	72.5	13.30	lb/MMscf	0.0111	lb/MMBtu	3.7	16.0	0.0019	lb/MMBtu	0.6	2.7	7.6	lb/MMscf	0.0075	lb/MMBtu	2.5	10.8	0.019	lb/MMBtu	6.3	27.5	4.90E-07	lb/MMBtu	1.6E-04	7.1E-04	0.17	0.74	1.80E-07	lb/MMBtu	6.0E-05	2.6E-04	1.18E-08	lb/MMBtu	3.9E-06	1.7E-05
New	H-101B	355.0	MMBtu/hr	3,109,800	MMBtu/yr	0.0054	lb/MMBtu	1.9	8.4	0.05	lb/MMBtu	17.8	77.7	13.30	lb/MMscf	0.0111	lb/MMBtu	3.9	17.2	0.0019	lb/MMBtu	0.7	2.9	7.6	lb/MMscf	0.0075	lb/MMBtu	2.6	11.6	0.019	lb/MMBtu	6.7	29.5	4.90E-07	lb/MMBtu	1.7E-04	7.6E-04	0.18	0.79	1.80E-07	lb/MMBtu	6.4E-05	2.8E-04	1.18E-08	lb/MMBtu	4.2E-06	1.8E-05
Hydroprocessing																																															
3UF																																																
SD	H-1	0.0	MMBtu/hr	0	MMBtu/yr																																										
SD	H-2	0.0	MMBtu/hr	0	MMBtu/yr																																										
SD	F-7	0.0	MMBtu/hr	0	MMBtu/yr																																										
4UF																																															
Oth	F-1	29.6	MMBtu/hr	259,296	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.098	lb/MMBtu	2.9	12.7	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.4	0.0019	lb/MMBtu	0.1	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	1.0	0.082	lb/MMBtu	2.4	10.7	4.90E-07	lb/MMBtu	1.5E-05	6.4E-05	0.02	0.07	1.80E-07	lb/MMBtu	5.3E-06	2.3E-05	1.18E-08	lb/MMBtu	3.5E-07	1.5E-06
Oth	F-8A	142.3	MMBtu/hr	1,246,548	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.4	0.275	lb/MMBtu	39.1	171.1	13.30	lb/MMscf	0.0111	lb/MMBtu	1.6	6.9	0.0019	lb/MMBtu	0.3	1.2	7.6	lb/MMscf	0.0075	lb/MMBtu	1.1	4.6	0.082	lb/MMBtu	11.7	51.3	4.90E-07	lb/MMBtu	7.0E-05	3.1E-04	0.07	0.32	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.3E-06
Oth	F-8B	142.3	MMBtu/hr	1,246,548	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.4	0.275	lb/MMBtu	39.1	171.1	13.30	lb/MMscf	0.0111	lb/MMBtu	1.6	6.9	0.0019	lb/MMBtu	0.3	1.2	7.6	lb/MMscf	0.0075	lb/MMBtu	1.1	4.6	0.082	lb/MMBtu	11.7	51.3	4.90E-07	lb/MMBtu	7.0E-05	3.1E-04	0.07	0.32	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.3E-06
Oth	F-2	169.9	MMBtu/hr	1,488,324	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.186	lb/MMBtu	31.6	138.6	13.30	lb/MMscf	0.0111	lb/MMBtu	1.9	8.2	0.0019	lb/MMBtu	0.3	1.4	7.6	lb/MMscf	0.0075	lb/MMBtu	1.3	5.5	0.082	lb/MMBtu	14.0	61.3	4.90E-07	lb/MMBtu	8.3E-05	3.6E-04	0.09	0.38	1.80E-07	lb/MMBtu	3.1E-05	1.3E-04	1.18E-08	lb/MMBtu	2.0E-06	8.8E-06
Oth	F-3	180.0	MMBtu/hr	1,576,800	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.3	0.275	lb/MMBtu	49.4	216.4	13.30	lb/MMscf	0.0111	lb/MMBtu	2.0	8.7	0.0019	lb/MMBtu	0.3	1.5	7.6	lb/MMscf	0.0075	lb/MMBtu	1.3	5.9	0.082	lb/MMBtu	14.8	64.9	4.90E-07	lb/MMBtu	8.8E-05	3.9E-04	0.09	0.40	1.80E-07	lb/MMBtu	3.2E-05	1.4E-04	1.18E-08	lb/MMBtu	2.1E-06	9.3E-06
Oth	F-4	96.8	MMBtu/hr	847,968	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.3	0.275	lb/MMBtu	26.6	116.4	13.30	lb/MMscf	0.0111	lb/MMBtu	1.1	4.7	0.0019	lb/MMBtu	0.2	0.8	7.6	lb/MMscf	0.0075	lb/MMBtu	0.7	3.2	0.082	lb/MMBtu	8.0	34.9	4.90E-07	lb/MMBtu	4.7E-05	2.1E-04	0.05	0.22	1.80E-07	lb/MMBtu	1.7E-05	7.6E-05	1.18E-08	lb/MMBtu	1.1E-06	5.0E-06
Oth	F-5	48.8	MMBtu/hr	427,488	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.098	lb/MMBtu	4.8	21.0	13.30	lb/MMscf	0.0111	lb/MMBtu	0.5	2.4	0.0019	lb/MMBtu	0.1	0.4	7.6	lb/MMscf	0.0075	lb/MMBtu	0.4	1.6	0.082	lb/MMBtu	4.0	17.6	4.90E-07	lb/MMBtu	2.4E-05	1.0E-04	0.02	0.11	1.80E-07	lb/MMBtu	8.8E-06	3.8E-05	1.18E-08	lb/MMBtu	5.7E-07	2.5E-06
Oth	F-6	21.7	MMBtu/hr	190,092	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.098	lb/MMBtu	2.1	9.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.2	1.1	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	1.8	7.8	4.90E-07	lb/MMBtu	1.1E-05	4.7E-05	0.01	0.05	1.80E-07	lb/MMBtu	3.9E-06	1.7E-05	1.18E-08	lb/MMBtu	2.6E-07	1.1E-06
Oth	F-7	36.2	MMBtu/hr	317,112	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.098	lb/MMBtu	3.5	15.5	13.30	lb/MMscf	0.0111	lb/MMBtu	0.4	1.8	0.0019	lb/MMBtu	0.1	0.3	7.6	lb/MMscf	0.0075	lb/MMBtu	0.3	1.2	0.082	lb/MMBtu	3.0	13.1	4.90E-07	lb/MMBtu	1.8E-05	7.8E-05	0.02	0.08	1.80E-07	lb/MMBtu	6.5E-06	2.9E-05	1.18E-08	lb/MMBtu	4.3E-07	1.9E-06
ARU																																															
Oth	F-200A	144.4	MMBtu/hr	1,264,944	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.4	0.275	lb/MMBtu	39.6	173.6	13.30	lb/MMscf	0.0111	lb/MMBtu	1.6	7.0	0.0019	lb/MMBtu	0.3	1.2	7.6	lb/MMscf	0.0075	lb/MMBtu	1.1	4.7	0.082	lb/MMBtu	11.9	52.1	4.90E-07	lb/MMBtu	7.1E-05	3.1E-04	0.07	0.32	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.4E-06
Oth	F-200B	144.4	MMBtu/hr	1,264,944	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.4	0.275	lb/MMBtu	39.6	173.6	13.30	lb/MMscf	0.0111	lb/MMBtu	1.6	7.0	0.0019	lb/MMBtu	0.3	1.2	7.6	lb/MMscf	0.0075	lb/MMBtu	1.1	4.7	0.082	lb/MMBtu	11.9	52.1	4.90E-07	lb/MMBtu	7.1E-05	3.1E-04	0.07	0.32	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.4E-06
BOU																																															
Mod	F-401	23.0	MMBtu/hr	201,480	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.098	lb/MMBtu	2.3	9.9	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.1	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	1.9	8.3	4.90E-07	lb/MMBtu	1.1E-05	4.9E-05	0.01	0.05	1.80E-07	lb/MMBtu	4.1E-06	1.8E-05	1.18E-08	lb/MMBtu	2.7E-07	1.2E-06
CFHU																																															
Oth	F-801A	24.6	MMBtu/hr	215,496	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.049	lb/MMBtu	1.2	5.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	2.0	8.9	4.90E-07	lb/MMBtu	1.2E-05	5.3E-05	0.01	0.05	1.80E-07	lb/MMBtu	4.4E-06	1.9E-05	1.18E-08	lb/MMBtu	2.9E-07	1.3E-06
Oth	F-801B	24.6	MMBtu/hr	215,496	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.049	lb/MMBtu	1.2	5.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	2.0	8.9	4.90E-07	lb/MMBtu	1.2E-05	5.3E-05	0.01	0.05	1.80E-07	lb/MMBtu	4.4E-06	1.9E-05	1.18E-08	lb/MMBtu	2.9E-07	1.3E-06
Oth	F-801C	24.6	MMBtu/hr	215,496	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.036	lb/MMBtu	0.9	3.9	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.8	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	1.2E-05	5.3E-05	0.01	0.05	1.80E-07	lb/MMBtu	4.4E-06	1.9E-05	1.18E-08	lb/MMBtu	2.9E-07	1.3E-06
GOHT																																															
New	F-901A	47.0	MMBtu/hr	411,720	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.04	lb/MMBtu	1.9	8.2	13.30	lb/MMscf	0.0111	lb/MMBtu	0.5	2.3	0.0019	lb/MMBtu	0.1	0.4	7.6	lb/MMscf	0.0075	lb/MMBtu	0.4	1.5	0.02	lb/MMBtu	0.9	4.1	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.02	0.10	1.80E-07	lb/MMBtu	8.5E-06	3.7E-05	1.18E-08	lb/MMBtu	5.5E-07	2.4E-06
New	F-901B	47.0	MMBtu/hr	411,720	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.04	lb/MMBtu	1.9	8.2	13.30	lb/MMscf	0.0111	lb/MMBtu	0.5	2.3	0.0019	lb/MMBtu	0.1	0.4	7.6	lb/MMscf	0.0075	lb/MMBtu	0.4	1.5	0.02	lb/MMBtu	0.9	4.1	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.02	0.10	1.80E-07	lb/MMBtu	8.5E-06	3.7E-05	1.18E-08	lb/MMBtu	5.5E-07	2.4E-06
CRU																																															
Oth	F-101	23.8	MMBtu/hr	208,488	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.08	lb/MMBtu	1.9	8.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	2.0	8.6	4.90E-07	lb/MMBtu	1.2E-05	5.1E-05	0.01	0.05	1.80E-07	lb/MMBtu	4.3E-06	1.9E-05	1.18E-08	lb/MMBtu	2.8E-07	1.2E-06
Oth	F-102	23.8	MMBtu/hr	208,488	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.08	lb/MMBtu	1.9	8.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.0	0.2	7.6	lb/MMscf	0.0075	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	2.0	8.6	4.90E-07	lb/MMBtu	1.2E-05	5.1E-05	0.01	0.05	1.80E-07	lb/MMBtu	4.3E-06	1.9E-05	1.18E-08	lb/MMBtu	2.8E-07	1.2E-06
DDU																																															
Oth	WB-301	70.8	MMBtu/hr	620,208	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.035	lb/MMBtu	2.4	10.7	13.30	lb/MMscf	0.0111	lb/MMBtu	0.8	3.4	0.0019	lb/MMBtu	0.1	0.6	7.6	lb/MMscf	0.0075	lb/MMBtu	0.5	2.3	0.04	lb/MMBtu	2.8	12.4	4.90E-07	lb/MMBtu	3.5E-05	1.5E-04	0.04	0.16	1.80E-07	lb/MMBtu	1.3E-05	5.6E-05	1.18E-08	lb/MMBtu	8.3E-07	3.6E-06
Oth	WB-302	55.8	MMBtu/hr	488,808	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.3	0.03	lb/MMBtu	1.7	7.3	13.30	lb/MMscf	0.0111	lb/MMBtu	0.6	2.7	0.0019	lb/MMBtu	0.1	0.5	7.6	lb/MMscf	0.0075	lb/MMBtu	0.4	1.8	0.04	lb/MMBtu	2.2	9.8	4.90E-07	lb/MMBtu	2.7E-05	1.2E-04	0.03	0.12	1.80E-07	lb/MMBtu	1.0E-05	4.4E-05	1.18E-08	lb/MMBtu	6.6E-07	2.9E-06
DHT																																															
New	B-601A	41.9	MMBtu/hr	367,044	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.04	lb/MMBtu	1.7	7.3	0.60	lb/MMscf	0.0006	lb/MMBtu	0.0	0.1	0.0019	lb/MMBtu	0.1	0.3	7.6	lb/MMscf	0.0075	lb/MMBtu	0.3	1.4	0.04	lb/MMBtu	1.7	7.3	4.90E-07	lb/MMBtu	2.1E-05	9.0E-05	0.00	0.00	1.80E-07	lb/MMBtu	7.5E-06	3.3E-05	1.18E-08	lb/MMBtu	4.9E-07	2.2E-06
ISOM																																															
Mod	H-1	153.2	MMBtu/hr	1,342,032	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.6	0.275	lb/MMBtu	42.1	184.2	13.30	lb/MMscf	0.0111	lb/MMBtu	1.7	7.4	0.0019	lb/MMBtu	0.3	1.2	7.6	lb/MMscf	0.0075	lb/MMBtu	1.1	5.0	0.082	lb/MMBtu	12.6	55.3	4.90E-07	lb/MMBtu	7.5E-05	3.3E-04	0.08	0.34	1.80E-07	lb/MMBtu	2.8E-05	1.2E-04	1.18E-08	lb/MMBtu	1.8E-06	7.9E-06
HU																																															
Oth	B-501	320.7	MMBtu/hr	2,809,332	MMBtu/yr	0.0054	lb/MMBtu	1.7	7.6	0.068	lb/MMBtu	21.6	94.8	13.30	lb/MMscf	0.0111	lb/MMBtu	3.5	15.5	0.0019	lb/MMBtu	0.6	2.6	7.6	lb/MMscf	0.0075	lb/MMBtu	2.4	10.5	0.02	lb/MMBtu	6.4	28.1	4.90E-07	lb/MMBtu	1.6E-04	6.9E-04	0.16	0.71	1.80E-07	lb/MMBtu	5.8E-05	2.5E-04	1.18E-08	lb/MMBtu	3.8E-06	1.7E-05
New HU (3rd Party SMR)																																															
New	HU-1 (natural gas)	230.0	MMBtu/hr	2,014,800	MMBtu/yr	0.0034	lb/MMBtu	0.8	3.4	0.013	lb/MMBtu	3.0	13.1	0.60	lb/MMscf	0.0006	lb/MMBtu	0.1	0.6	0.0068	lb/MMBtu	1.6	6.9	0.0068	lb/MMBtu	0.0068	lb/MMBtu	1.6	6.9	0.015	lb/MMBtu	3.5	15.1	4.90E-07	lb/MMBtu	1.1E-04	4.9E-04	0.0	0.03	1.80E-07	lb/MMBtu	4.1E-05	1.8E-04	1.18E-08	lb/MMBtu	2.7E-06	1.2E-05
	HU-1 (PSA tail gas)	690.0	MMBtu/hr	6,044,400	MMBtu/yr	0.0034	lb/MMBtu	2.3	10.3	0.013	lb/MMBtu	9.0	39.3	0.00	lb/MMscf	0.0	lb/MMBtu	-	0.0	0.0068	lb/MMBtu	4.7	20.6	0.0068	lb/MMBtu	0.0068	lb/MMBtu	4.7	20.6	0.015	lb/MMBtu	10.4	45.3														
New	HU-2 (natural gas)	230.0	MMBtu/hr	2,014,800	MMBtu/yr	0.0034	lb/MMBtu	0.8	3.4	0.013	lb/MMBtu	3.0	13.1	0.60	lb/MMscf	0.0006	lb/MMBtu	0.1	0.6	0.0068	lb/MMBtu	1.6	6.9	0.0068	lb/MMBtu	0.0068	lb/MMBtu	1.6	6.9	0.015	lb/MMBtu	3.5	15.1	4.90E-07	lb/MMBtu	1.1E-04	4.9E-04	0.0	0.03	1.80E-07	lb/MMBtu	4.1E-05	1.8E-04

Table C.12. 1999 Combustion Emissions

Process Heaters and Boilers

Code	Process Unit	Usage				VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[2]				CO				Pb				H_2SO_4 Mist		Hg				Be			
						EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
Crude and Coking																																											
11A PS																																											
Oth	H-1X	146.8	MMBtu/hr	1,286,310	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.1660	lb/MMBtu	24.4	106.8	0.0187	lb/MMBtu	2.7	12.0	0.0019	lb/MMBtu	0.3	1.2	0.0075	lb/MMBtu	1.1	4.8	0.082	lb/MMBtu	12.1	53.0	4.90E-07	lb/MMBtu	7.2E-05	3.2E-04	0.13	0.55	1.80E-07	lb/MMBtu	2.6E-05	1.2E-04	1.18E-08	lb/MMBtu	1.7E-06	7.6E-06
Oth	H-2	19.7	MMBtu/hr	172,977	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0980	lb/MMBtu	1.9	8.5	0.0187	lb/MMBtu	0.4	1.6	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	1.6	7.1	4.90E-07	lb/MMBtu	9.7E-06	4.2E-05	0.02	0.07	1.80E-07	lb/MMBtu	3.6E-06	1.6E-05	1.18E-08	lb/MMBtu	2.3E-07	1.0E-06
Oth	H-3	33.8	MMBtu/hr	296,101	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.3	14.5	0.0187	lb/MMBtu	0.6	2.8	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.3	1.1	0.082	lb/MMBtu	2.8	12.2	4.90E-07	lb/MMBtu	1.7E-05	7.3E-05	0.03	0.13	1.80E-07	lb/MMBtu	6.1E-06	2.7E-05	1.18E-08	lb/MMBtu	4.0E-07	1.7E-06
11C PS																																											
Cont	H-200	99.0	MMBtu/hr	867,329	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.3	0.2745	lb/MMBtu	27.2	119.0	0.0187	lb/MMBtu	1.9	8.1	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.7	3.2	0.082	lb/MMBtu	8.2	35.7	4.90E-07	lb/MMBtu	4.9E-05	2.1E-04	0.09	0.37	1.80E-07	lb/MMBtu	1.8E-05	7.8E-05	1.18E-08	lb/MMBtu	1.2E-06	5.1E-06
Oth	H-300	85.5	MMBtu/hr	749,162	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.0	0.1373	lb/MMBtu	11.7	51.4	0.0187	lb/MMBtu	1.6	7.0	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.6	2.8	0.082	lb/MMBtu	7.0	30.8	4.90E-07	lb/MMBtu	4.2E-05	1.8E-04	0.07	0.32	1.80E-07	lb/MMBtu	1.5E-05	6.7E-05	1.18E-08	lb/MMBtu	1.0E-06	4.4E-06
Coker																																											
SD	H-101	48.4	MMBtu/hr	423,821	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0980	lb/MMBtu	4.7	20.8	0.0187	lb/MMBtu	0.9	4.0	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	4.0	17.5	4.90E-07	lb/MMBtu	2.4E-05	1.0E-04	0.04	0.18	1.80E-07	lb/MMBtu	8.7E-06	3.8E-05	1.18E-08	lb/MMBtu	5.7E-07	2.5E-06
SD	H-102	52.6	MMBtu/hr	460,694	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.0980	lb/MMBtu	5.2	22.6	0.0187	lb/MMBtu	1.0	4.3	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	4.3	19.0	4.90E-07	lb/MMBtu	2.6E-05	1.1E-04	0.05	0.20	1.80E-07	lb/MMBtu	9.5E-06	4.1E-05	1.18E-08	lb/MMBtu	6.2E-07	2.7E-06
SD	H-103	52.6	MMBtu/hr	460,575	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.0980	lb/MMBtu	5.2	22.6	0.0187	lb/MMBtu	1.0	4.3	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	4.3	19.0	4.90E-07	lb/MMBtu	2.6E-05	1.1E-04	0.05	0.20	1.80E-07	lb/MMBtu	9.5E-06	4.1E-05	1.18E-08	lb/MMBtu	6.2E-07	2.7E-06
SD	H-104	52.6	MMBtu/hr	461,002	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.0980	lb/MMBtu	5.2	22.6	0.0187	lb/MMBtu	1.0	4.3	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	4.3	19.0	4.90E-07	lb/MMBtu	2.6E-05	1.1E-04	0.05	0.20	1.80E-07	lb/MMBtu	9.5E-06	4.1E-05	1.18E-08	lb/MMBtu	6.2E-07	2.7E-06
12PS																																											
SD	H-1AN	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.2745	lb/MMBtu	0.0	0.0	0.0187	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0075	lb/MMBtu	0.0	0.0	0.082	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.00	0.00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.18E-08	lb/MMBtu	0.0E+00	0.0E+00
SD	H-1AS	100.3	MMBtu/hr	878,915	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.4	0.2745	lb/MMBtu	27.5	120.6	0.0187	lb/MMBtu	1.9	8.2	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.7	3.3	0.082	lb/MMBtu	8.3	36.2	4.90E-07	lb/MMBtu	4.9E-05	2.2E-04	0.09	0.38	1.80E-07	lb/MMBtu	1.8E-05	7.9E-05	1.18E-08	lb/MMBtu	1.2E-06	5.2E-06
SD	H-1B	168.6	MMBtu/hr	1,477,301	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.2745	lb/MMBtu	46.3	202.8	0.0187	lb/MMBtu	3.2	13.8	0.0019	lb/MMBtu	0.3	1.4	0.0075	lb/MMBtu	1.3	5.5	0.082	lb/MMBtu	13.9	60.8	4.90E-07	lb/MMBtu	8.3E-05	3.6E-04	0.14	0.63	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.18E-08	lb/MMBtu	2.0E-06	8.7E-06
SD	H-2	97.6	MMBtu/hr	855,243	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.3	0.0360	lb/MMBtu	3.5	15.4	0.0187	lb/MMBtu	1.8	8.0	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.7	3.2	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	4.8E-05	2.1E-04	0.08	0.37	1.80E-07	lb/MMBtu	1.8E-05	7.7E-05	1.18E-08	lb/MMBtu	1.1E-06	5.0E-06
SD	H-1CN	34.8	MMBtu/hr	304,411	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.4	14.9	0.0187	lb/MMBtu	0.7	2.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.9	12.5	4.90E-07	lb/MMBtu	1.7E-05	7.5E-05	0.03	0.13	1.80E-07	lb/MMBtu	6.3E-06	2.7E-05	1.18E-08	lb/MMBtu	4.1E-07	1.8E-06
SD	H-1CX	197.8	MMBtu/hr	1,733,057	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.7	0.0990	lb/MMBtu	19.6	85.8	0.0187	lb/MMBtu	3.7	16.2	0.0019	lb/MMBtu	0.4	1.6	0.0040	lb/MMBtu	0.8	3.5	0.082	lb/MMBtu	16.3	71.4	4.90E-07	lb/MMBtu	9.7E-05	4.2E-04	0.17	0.74	1.80E-07	lb/MMBtu	3.6E-05	1.6E-04	1.18E-08	lb/MMBtu	2.3E-06	1.0E-05
Hydroprocessing																																											
3UF																																											
SD	H-1	166.9	MMBtu/hr	1,461,875	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.9	0.2745	lb/MMBtu	45.8	200.6	0.0050	lb/MMBtu	0.8	3.6	0.0019	lb/MMBtu	0.3	1.4	0.0040	lb/MMBtu	0.7	2.9	0.082	lb/MMBtu	13.7	60.2	4.90E-07	lb/MMBtu	8.2E-05	3.6E-04	0.04	0.17	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.18E-08	lb/MMBtu	2.0E-06	8.6E-06
SD	H-2	146.7	MMBtu/hr	1,285,206	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.2745	lb/MMBtu	40.3	176.4	0.0050	lb/MMBtu	0.7	3.2	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.6	0.082	lb/MMBtu	12.1	52.9	4.90E-07	lb/MMBtu	7.2E-05	3.2E-04	0.03	0.15	1.80E-07	lb/MMBtu	2.6E-05	1.2E-04	1.18E-08	lb/MMBtu	1.7E-06	7.6E-06
SD	F-7	19.3	MMBtu/hr	168,876	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0980	lb/MMBtu	1.9	8.3	0.0050	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.6	7.0	4.90E-07	lb/MMBtu	9.5E-06	4.1E-05	0.00	0.02	1.80E-07	lb/MMBtu	3.5E-06	1.5E-05	1.18E-08	lb/MMBtu	2.3E-07	9.9E-07
4UF																																											
Oth	F-1	47.0	MMBtu/hr	411,924	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0980	lb/MMBtu	4.6	20.2	0.0054	lb/MMBtu	0.3	1.1	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.9	17.0	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.01	0.05	1.80E-07	lb/MMBtu	8.5E-06	3.7E-05	1.18E-08	lb/MMBtu	5.5E-07	2.4E-06
Oth	F-8A	122.4	MMBtu/hr	1,072,493	MMBtu/yr	0.0054	lb/MMBtu	0.7	2.9	0.2745	lb/MMBtu	33.6	147.2	0.0054	lb/MMBtu	0.7	2.9	0.0019	lb/MMBtu	0.2	1.0	0.0040	lb/MMBtu	0.5	2.1	0.082	lb/MMBtu	10.1	44.2	4.90E-07	lb/MMBtu	6.0E-05	2.6E-04	0.03	0.13	1.80E-07	lb/MMBtu	2.2E-05	9.7E-05	1.18E-08	lb/MMBtu	1.4E-06	6.3E-06
Oth	F-8B	116.0	MMBtu/hr	1,016,141	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.7	0.2745	lb/MMBtu	31.8	139.5	0.0054	lb/MMBtu	0.6	2.8	0.0019	lb/MMBtu	0.2	0.9	0.0040	lb/MMBtu	0.5	2.0	0.082	lb/MMBtu	9.6	41.8	4.90E-07	lb/MMBtu	5.7E-05	2.5E-04	0.03	0.13	1.80E-07	lb/MMBtu	2.1E-05	9.1E-05	1.18E-08	lb/MMBtu	1.4E-06	6.0E-06
Oth	F-2	267.5	MMBtu/hr	2,343,419	MMBtu/yr	0.0054	lb/MMBtu	1.4	6.3	0.1863	lb/MMBtu	49.8	218.3	0.0054	lb/MMBtu	1.5	6.4	0.0019	lb/MMBtu	0.5	2.2	0.0040	lb/MMBtu	1.1	4.6	0.082	lb/MMBtu	22.0	96.5	4.90E-07	lb/MMBtu	1.3E-04	5.7E-04	0.07	0.29	1.80E-07	lb/MMBtu	4.8E-05	2.1E-04	1.18E-08	lb/MMBtu	3.1E-06	1.4E-05
Oth	F-3	221.9	MMBtu/hr	1,944,248	MMBtu/yr	0.0054	lb/MMBtu	1.2	5.2	0.2745	lb/MMBtu	60.9	266.9	0.0054	lb/MMBtu	1.2	5.3	0.0019	lb/MMBtu	0.4	1.8	0.0040	lb/MMBtu	0.9	3.9	0.082	lb/MMBtu	18.3	80.1	4.90E-07	lb/MMBtu	1.1E-04	4.8E-04	0.06	0.24	1.80E-07	lb/MMBtu	4.0E-05	1.7E-04	1.18E-08	lb/MMBtu	2.6E-06	1.1E-05
Oth	F-4	141.7	MMBtu/hr	1,241,323	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.3	0.2745	lb/MMBtu	38.9	170.4	0.0054	lb/MMBtu	0.8	3.4	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.5	0.082	lb/MMBtu	11.7	51.1	4.90E-07	lb/MMBtu	6.9E-05	3.0E-04	0.04	0.15	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.3E-06
Oth	F-5	45.2	MMBtu/hr	396,291	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.1	0.0980	lb/MMBtu	4.4	19.4	0.0054	lb/MMBtu	0.2	1.1	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.7	16.3	4.90E-07	lb/MMBtu	2.2E-05	9.7E-05	0.01	0.05	1.80E-07	lb/MMBtu	8.1E-06	3.6E-05	1.18E-08	lb/MMBtu	5.3E-07	2.3E-06
Oth	F-6	47.1	MMBtu/hr	412,712	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0980	lb/MMBtu	4.6	20.2	0.0054	lb/MMBtu	0.3	1.1	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.9	17.0	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.01	0.05	1.80E-07	lb/MMBtu	8.5E-06	3.7E-05	1.18E-08	lb/MMBtu	5.5E-07	2.4E-06
Oth	F-7	32.7	MMBtu/hr	286,821	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.2	14.1	0.0054	lb/MMBtu	0.2	0.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.7	11.8	4.90E-07	lb/MMBtu	1.6E-05	7.0E-05	0.01	0.04	1.80E-07	lb/MMBtu	5.9E-06	2.6E-05	1.18E-08	lb/MMBtu	3.9E-07	1.7E-06
ARU																																											
Oth	F-200A	199.2	MMBtu/hr	1,744,854	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.7	0.2745	lb/MMBtu	54.7	239.5	0.0187	lb/MMBtu	3.7	16.3	0.0019	lb/MMBtu	0.4	1.6	0.0040	lb/MMBtu	0.8	3.5	0.082	lb/MMBtu	16.4	71.8	4.90E-07	lb/MMBtu	9.8E-05	4.3E-04	0.17	0.75	1.80E-07	lb/MMBtu	3.6E-05	1.6E-04	1.18E-08	lb/MMBtu	2.3E-06	1.0E-05
Oth	F-200B	210.9	MMBtu/hr	1,847,296	MMBtu/yr	0.0054	lb/MMBtu	1.1	5.0	0.2745	lb/MMBtu	57.9	253.6	0.0187	lb/MMBtu	3.9	17.3	0.0019	lb/MMBtu	0.4	1.7	0.0040	lb/MMBtu	0.8	3.7	0.082	lb/MMBtu	17.4	76.1	4.90E-07	lb/MMBtu	1.0E-04	4.5E-04	0.18	0.79	1.80E-07	lb/MMBtu	3.8E-05	1.7E-04	1.18E-08	lb/MMBtu	2.5E-06	1.1E-05
BOU																																											
Mod	F-401	13.7	MMBtu/hr	119,952	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0980	lb/MMBtu	1.3	5.9	0.0054	lb/MMBtu	0.1	0.3	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.2	0.082	lb/MMBtu	1.1	4.9	4.90E-07	lb/MMBtu	6.7E-06	2.9E-05	0.00	0.01	1.80E-07	lb/MMBtu	2.5E-06	1.1E-05	1.18E-08	lb/MMBtu	1.6E-07	7.1E-07
CFHU																																											
Oth	F-801A	12.2	MMBtu/hr	107,139	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0490	lb/MMBtu	0.6	2.6	0.0049	lb/MMBtu	0.1	0.3	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	1.0	4.4	4.90E-07	lb/MMBtu	6.0E-06	2.6E-05	0.00	0.01	1.80E-07	lb/MMBtu	2.2E-06	9.6E-06	1.18E-08	lb/MMBtu	1.4E-07	6.3E-07
Oth	F-801B	12.2	MMBtu/hr	107,139	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0490	lb/MMBtu	0.6	2.6	0.0049	lb/MMBtu	0.1	0.3	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	1.0	4.4	4.90E-07	lb/MMBtu	6.0E-06	2.6E-05	0.00	0.01	1.80E-07	lb/MMBtu	2.2E-06	9.6E-06	1.18E-08	lb/MMBtu	1.4E-07	6.3E-07
Oth	F-801C	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.0360	lb/MMBtu	0.0	0.0	0.0049	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0040	lb/MMBtu	0.0	0.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.00	0.00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.18E-08	lb/MMBtu	0.0E+00	0.0E+00
CRU																																											
Oth	F-101	41.3	MMBtu/hr	361,928	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0800	lb/MMBtu	3.3	14.5	0.0050	lb/MMBtu	0.2	0.9	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.4	14.9	4.90E-07	lb/MMBtu	2.0E-05	8.9E-05	0.01	0.04	1.80E-07	lb/MMBtu	7.4E-06	3.3E-05	1.18E-08	lb/MMBtu	4.9E-07	2.1E-06
Oth	F-102	19.3	MMBtu/hr	169,317	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0800	lb/MMBtu	1.5	6.8	0.0050	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.6	7.0	4.90E-07	lb/MMBtu	9.5E-06	4.1E-05	0.00	0.02	1.80E-07	lb/MMBtu	3.5E-06	1.5E-05	1.18E-08	lb/MMBtu	2.3E-07	1.0E-06
DDU																																											
Oth	WB-301	40.2	MMBtu/hr	352,461	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0346	lb/MMBtu	1.4	6.1	0.0187	lb/MMBtu	0.8	3.3	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.040	lb/MMBtu	1.6	7.0	4.90E-07	lb/MMBtu	2.0E-05	8.6E-05	0.03	0.15	1.80E-07	lb/MMBtu	7.2E-06	3.2E-05	1.18E-08	lb/MMBtu	4.7E-07	2.1E-06
Oth	WB-302	66.5	MMBtu/hr	582,883	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.6	0.0300	lb/MMBtu	2.0	8.7	0.0187	lb/MMBtu	1.2	5.5	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.2	1.1	0.040	lb/MMBtu	2.7	11.7	4.90E-07	lb/MMBtu	3.3E-05	1.4E-04	0.06	0.25	1.80E-07	lb/MMBtu	1.2E-05	5.2E-05	1.18E-08	lb/MMBtu	7.8E-07	3.4E-06
ISOM																																											
Mod	H-1	208.3	MMBtu/hr	1,824,954	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.9	0.2745	lb/MMBtu	57.2	250.5	0.0187	lb/MMBtu	3.9	17.1	0.0019	lb/MMBtu	0.4	1.7	0.0040	lb/MMBtu	0.7	3.1	0.082	lb/MMBtu	17.2	75.1	4.90E-07	lb/MMBtu	1.0E-04	4.5E-04	0.18	0.78	1.80E-07	lb/MMBtu	3.7E-05	1.6E-04	1.18E-08	lb/MMBtu	2.5E-06	1.1E-05
HU																																											
Oth	B-501	164.6	MMBtu/hr	1,441,540	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.9	0.0675	lb/MMBtu	11.1	48.7	0.0618	lb/MMBtu	10.2	44.6	0.0019	lb/MMBtu	0.3	1.3	0.0075	lb/MMBtu	1.2	5.4	0.02	lb/MMBtu	3.3	14.4	4.90E-07	lb/MMBtu	8.1E-05	3.5E-04	0.47	2.04	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.18E-08	lb/MMBtu	1.9E-06	8.5E-06
Utilities																																											
1SPS																																											
SD	Boiler 3	43.5	MMBtu/hr	381,467	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.1570	lb/MMBtu	6.8	29.9	0.0187	lb/MMBtu	0.8	3.6	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.3	1.4	0.049	lb/MMBtu	2.1	9.3	4.90E-07	lb/MMBtu	2.1E-05	9.3E-05	0.04	0.16	1.80E-07	lb/MMBtu	7.8E-06	3.4E-05	1.18E-08	lb/MMBtu	5.1E-07	2.2E-06
SD	Boiler 4	61.7	MMBtu/hr	540,317	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.5	0.1570	lb/MMBtu	9.7	42.4	0.0187	lb/MMBtu	1.2	5.1	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.5	2.0	0.049	lb/MMBtu	3.0	13.2	4.90E-07	lb/MMBtu	3.0E-05	1.3E-04	0.05	0.23	1.80E-07	lb/MMBtu	1.1E-05	4.9E-05	1.18E-08	lb/MMBtu	7.3E-07	3.2E-06
SD	Boiler 5	40.2	MMBtu/hr	351,888	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0930	lb/MMBtu	3.7	16.4	0.0187	lb/MMBtu	0.8	3.3	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.3	1.3	0.248	lb/MMBtu	10.0	43.6	4.90E-07	lb/MMBtu	2.0E-05	8.6E-05	0.03	0.15	1.80E-07	lb/MMBtu	7.2E-06	3.2E-05	1.18E-08	lb/MMBtu	4.7E-07	2.1E-06
SD	Boiler 6	26.4	MMBtu/hr	231,476	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0930	lb/MMBtu	2.5	10.8	0.0187	lb/MMBtu	0.5	2.2	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.2	0.9	0.248	lb/MMBtu	6.6	28.7	4.90E-07	lb/MMBtu	1.3E-05	5.7E-05	0.02	0.10	1.80E-07	lb/MMBtu	4.8E-06	2.1E-05	1.18E-08	lb/MMBtu	3.1E-07	1.4E-06
SD	Boiler 7	51.7	MMBtu/hr	452,503	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.0930	lb/MMBtu	4.8	21.0	0.0187	lb/MMBtu	1.0	4.2	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.4	1.7	0.248	lb/MMBtu	12.8	56.1	4.90E-07	lb/MMBtu	2.5E-05	1.1E-04	0.04	0.19	1.80E-07	lb/MMBtu	9.3E-06	4.1E-05	1.18E-08	lb/MMBtu	6.1E-07	2.7E-06
Lakefront																																											
SD	FBI	39,365	tons feed			0.34	lb/unit feed	1.5	6.7	0.14	lb/unit feed	0.6	2.8	0.13	lb/unit feed	0.6	2.6	0.184	lb/unit feed	0.8	3.6	0.184	lb/unit feed	0.8

Table C.13. 2000 Combustion Emissions

Process Heaters and Boilers

Code	Process Unit	Usage				VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[2]				CO				Pb				H_2SO_4 Mist		Hg				Be			
						EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
Crude and Coking																																											
11A PS																																											
Oth	H-1X	130.2	MMBtu/hr	1,140,204	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.1	0.1660	lb/MMBtu	21.6	94.6	0.0214	lb/MMBtu	2.8	12.2	0.0019	lb/MMBtu	0.2	1.1	0.0075	lb/MMBtu	1.0	4.2	0.082	lb/MMBtu	10.7	46.9	4.90E-07	lb/MMBtu	6.4E-05	2.8E-04	0.13	0.56	1.80E-07	lb/MMBtu	2.3E-05	1.0E-04	1.20E-05	lb/MMBtu	1.5E-06	6.7E-06
Oth	H-2	21.7	MMBtu/hr	189,885	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0980	lb/MMBtu	2.1	9.3	0.0214	lb/MMBtu	0.5	2.0	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	1.8	7.8	4.90E-07	lb/MMBtu	1.1E-05	4.7E-05	0.02	0.09	1.80E-07	lb/MMBtu	3.9E-06	1.7E-05	1.20E-05	lb/MMBtu	2.6E-07	1.1E-06
Oth	H-3	32.8	MMBtu/hr	287,244	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.2	14.1	0.0214	lb/MMBtu	0.7	3.1	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.2	1.1	0.082	lb/MMBtu	2.7	11.8	4.90E-07	lb/MMBtu	1.6E-05	7.0E-05	0.03	0.14	1.80E-07	lb/MMBtu	5.9E-06	2.6E-05	1.20E-05	lb/MMBtu	3.9E-07	1.7E-06
11C PS																																											
Cont	H-200	86.3	MMBtu/hr	756,300	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.0	0.2745	lb/MMBtu	23.7	103.8	0.0214	lb/MMBtu	1.8	8.1	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.6	2.8	0.082	lb/MMBtu	7.1	31.1	4.90E-07	lb/MMBtu	4.2E-05	1.9E-04	0.08	0.37	1.80E-07	lb/MMBtu	1.6E-05	6.8E-05	1.20E-05	lb/MMBtu	1.0E-06	4.4E-06
Oth	H-300	72.5	MMBtu/hr	635,479	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.1373	lb/MMBtu	10.0	43.6	0.0214	lb/MMBtu	1.5	6.8	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.5	2.4	0.082	lb/MMBtu	6.0	26.2	4.90E-07	lb/MMBtu	3.6E-05	1.6E-04	0.07	0.31	1.80E-07	lb/MMBtu	1.3E-05	5.7E-05	1.20E-05	lb/MMBtu	8.5E-07	3.7E-06
Coker																																											
SD	H-101	40.9	MMBtu/hr	358,143	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.0	17.6	0.0214	lb/MMBtu	0.9	3.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.4	14.7	4.90E-07	lb/MMBtu	2.0E-05	8.8E-05	0.04	0.18	1.80E-07	lb/MMBtu	7.4E-06	3.2E-05	1.20E-05	lb/MMBtu	4.8E-07	2.1E-06
SD	H-102	44.8	MMBtu/hr	392,147	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.1	0.0980	lb/MMBtu	4.4	19.2	0.0214	lb/MMBtu	1.0	4.2	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.7	16.1	4.90E-07	lb/MMBtu	2.2E-05	9.6E-05	0.04	0.19	1.80E-07	lb/MMBtu	8.1E-06	3.5E-05	1.20E-05	lb/MMBtu	5.3E-07	2.3E-06
SD	H-103	42.7	MMBtu/hr	374,401	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.2	18.4	0.0214	lb/MMBtu	0.9	4.0	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.5	15.4	4.90E-07	lb/MMBtu	2.1E-05	9.2E-05	0.04	0.18	1.80E-07	lb/MMBtu	7.7E-06	3.4E-05	1.20E-05	lb/MMBtu	5.0E-07	2.2E-06
SD	H-104	42.5	MMBtu/hr	372,259	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.2	18.2	0.0214	lb/MMBtu	0.9	4.0	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.5	15.3	4.90E-07	lb/MMBtu	2.1E-05	9.1E-05	0.04	0.18	1.80E-07	lb/MMBtu	7.6E-06	3.4E-05	1.20E-05	lb/MMBtu	5.0E-07	2.2E-06
12PS																																											
SD	H-1AN	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.2745	lb/MMBtu	0.0	0.0	0.0214	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0075	lb/MMBtu	0.0	0.0	0.082	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.00	0.00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.20E-05	lb/MMBtu	0.0E+00	0.0E+00
SD	H-1AS	95.8	MMBtu/hr	839,531	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.3	0.2745	lb/MMBtu	26.3	115.2	0.0214	lb/MMBtu	2.0	9.0	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.7	3.1	0.082	lb/MMBtu	7.9	34.6	4.90E-07	lb/MMBtu	4.7E-05	2.1E-04	0.09	0.41	1.80E-07	lb/MMBtu	1.7E-05	7.6E-05	1.20E-05	lb/MMBtu	1.1E-06	4.9E-06
SD	H-1B	168.5	MMBtu/hr	1,476,481	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.2745	lb/MMBtu	46.3	202.7	0.0214	lb/MMBtu	3.6	15.8	0.0019	lb/MMBtu	0.3	1.4	0.0075	lb/MMBtu	1.3	5.5	0.082	lb/MMBtu	13.9	60.8	4.90E-07	lb/MMBtu	8.3E-05	3.6E-04	0.17	0.72	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.20E-05	lb/MMBtu	2.0E-06	8.7E-06
SD	H-2	92.5	MMBtu/hr	810,314	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.2	0.0360	lb/MMBtu	3.3	14.6	0.0214	lb/MMBtu	2.0	8.7	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.7	3.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	4.5E-05	2.0E-04	0.09	0.40	1.80E-07	lb/MMBtu	1.7E-05	7.3E-05	1.20E-05	lb/MMBtu	1.1E-06	4.8E-06
SD	H-1CN	34.0	MMBtu/hr	298,064	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.3	14.6	0.0214	lb/MMBtu	0.7	3.2	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.8	12.3	4.90E-07	lb/MMBtu	1.7E-05	7.3E-05	0.03	0.15	1.80E-07	lb/MMBtu	6.1E-06	2.7E-05	1.20E-05	lb/MMBtu	4.0E-07	1.8E-06
SD	H-1CX	168.5	MMBtu/hr	1,476,360	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.0990	lb/MMBtu	16.7	73.1	0.0214	lb/MMBtu	3.6	15.8	0.0019	lb/MMBtu	0.3	1.4	0.0040	lb/MMBtu	0.7	3.0	0.082	lb/MMBtu	13.9	60.8	4.90E-07	lb/MMBtu	8.3E-05	3.6E-04	0.17	0.72	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.20E-05	lb/MMBtu	2.0E-06	8.7E-06
Hydroprocessing																																											
3UF																																											
SD	H-1	148.6	MMBtu/hr	1,301,376	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.2745	lb/MMBtu	40.8	178.6	0.0079	lb/MMBtu	1.2	5.1	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.6	0.082	lb/MMBtu	12.2	53.6	4.90E-07	lb/MMBtu	7.3E-05	3.2E-04	0.05	0.24	1.80E-07	lb/MMBtu	2.7E-05	1.2E-04	1.20E-05	lb/MMBtu	1.7E-06	7.7E-06
SD	H-2	141.3	MMBtu/hr	1,238,145	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.3	0.2745	lb/MMBtu	38.8	169.9	0.0079	lb/MMBtu	1.1	4.9	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.5	0.082	lb/MMBtu	11.6	51.0	4.90E-07	lb/MMBtu	6.9E-05	3.0E-04	0.05	0.22	1.80E-07	lb/MMBtu	2.5E-05	1.1E-04	1.20E-05	lb/MMBtu	1.7E-06	7.3E-06
SD	F-7	19.1	MMBtu/hr	167,265	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0980	lb/MMBtu	1.9	8.2	0.0079	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.6	6.9	4.90E-07	lb/MMBtu	9.4E-06	4.1E-05	0.01	0.03	1.80E-07	lb/MMBtu	3.4E-06	1.5E-05	1.20E-05	lb/MMBtu	2.2E-07	9.8E-07
4UF																																											
Oth	F-1	28.9	MMBtu/hr	253,233	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	2.8	12.4	0.0056	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.4	10.4	4.90E-07	lb/MMBtu	1.4E-05	6.2E-05	0.01	0.03	1.80E-07	lb/MMBtu	5.2E-06	2.3E-05	1.20E-05	lb/MMBtu	3.4E-07	1.5E-06
Oth	F-8A	74.7	MMBtu/hr	654,389	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.2745	lb/MMBtu	20.5	89.8	0.0056	lb/MMBtu	0.4	1.8	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.3	1.3	0.082	lb/MMBtu	6.2	26.9	4.90E-07	lb/MMBtu	3.7E-05	1.6E-04	0.02	0.08	1.80E-07	lb/MMBtu	1.3E-05	5.9E-05	1.20E-05	lb/MMBtu	8.8E-07	3.8E-06
Oth	F-8B	69.7	MMBtu/hr	610,848	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.6	0.2745	lb/MMBtu	19.1	83.8	0.0056	lb/MMBtu	0.4	1.7	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.3	1.2	0.082	lb/MMBtu	5.7	25.2	4.90E-07	lb/MMBtu	3.4E-05	1.5E-04	0.02	0.08	1.80E-07	lb/MMBtu	1.3E-05	5.5E-05	1.20E-05	lb/MMBtu	8.2E-07	3.6E-06
Oth	F-2	184.0	MMBtu/hr	1,611,778	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.3	0.1863	lb/MMBtu	34.3	150.1	0.0056	lb/MMBtu	1.0	4.5	0.0019	lb/MMBtu	0.3	1.5	0.0040	lb/MMBtu	0.7	3.2	0.082	lb/MMBtu	15.2	66.4	4.90E-07	lb/MMBtu	9.0E-05	4.0E-04	0.05	0.21	1.80E-07	lb/MMBtu	3.3E-05	1.5E-04	1.20E-05	lb/MMBtu	2.2E-06	9.5E-06
Oth	F-3	180.9	MMBtu/hr	1,584,466	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.3	0.2745	lb/MMBtu	49.7	217.5	0.0056	lb/MMBtu	1.0	4.5	0.0019	lb/MMBtu	0.3	1.5	0.0040	lb/MMBtu	0.7	3.2	0.082	lb/MMBtu	14.9	65.2	4.90E-07	lb/MMBtu	8.9E-05	3.9E-04	0.05	0.20	1.80E-07	lb/MMBtu	3.3E-05	1.4E-04	1.20E-05	lb/MMBtu	2.1E-06	9.3E-06
Oth	F-4	100.6	MMBtu/hr	881,291	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.4	0.2745	lb/MMBtu	27.6	121.0	0.0056	lb/MMBtu	0.6	2.5	0.0019	lb/MMBtu	0.2	0.8	0.0040	lb/MMBtu	0.4	1.8	0.082	lb/MMBtu	8.3	36.3	4.90E-07	lb/MMBtu	4.9E-05	2.2E-04	0.03	0.11	1.80E-07	lb/MMBtu	1.8E-05	7.9E-05	1.20E-05	lb/MMBtu	1.2E-06	5.2E-06
Oth	F-5	42.8	MMBtu/hr	374,869	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.2	18.4	0.0056	lb/MMBtu	0.2	1.1	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.5	15.4	4.90E-07	lb/MMBtu	2.1E-05	9.2E-05	0.01	0.05	1.80E-07	lb/MMBtu	7.7E-06	3.4E-05	1.20E-05	lb/MMBtu	5.0E-07	2.2E-06
Oth	F-6	33.1	MMBtu/hr	290,286	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.2	14.2	0.0056	lb/MMBtu	0.2	0.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.7	12.0	4.90E-07	lb/MMBtu	1.6E-05	7.1E-05	0.01	0.04	1.80E-07	lb/MMBtu	6.0E-06	2.6E-05	1.20E-05	lb/MMBtu	3.9E-07	1.7E-06
Oth	F-7	30.4	MMBtu/hr	266,092	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	3.0	13.0	0.0056	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.5	11.0	4.90E-07	lb/MMBtu	1.5E-05	6.5E-05	0.01	0.03	1.80E-07	lb/MMBtu	5.5E-06	2.4E-05	1.20E-05	lb/MMBtu	3.6E-07	1.6E-06
ARU																																											
Oth	F-200A	130.8	MMBtu/hr	1,146,143	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.1	0.2745	lb/MMBtu	35.9	157.3	0.0214	lb/MMBtu	2.8	12.2	0.0019	lb/MMBtu	0.2	1.1	0.0040	lb/MMBtu	0.5	2.3	0.082	lb/MMBtu	10.8	47.2	4.90E-07	lb/MMBtu	6.4E-05	2.8E-04	0.13	0.56	1.80E-07	lb/MMBtu	2.4E-05	1.0E-04	1.20E-05	lb/MMBtu	1.5E-06	6.7E-06
Oth	F-200B	129.2	MMBtu/hr	1,132,105	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.1	0.2745	lb/MMBtu	35.5	155.4	0.0214	lb/MMBtu	2.8	12.1	0.0019	lb/MMBtu	0.2	1.1	0.0040	lb/MMBtu	0.5	2.3	0.082	lb/MMBtu	10.6	46.6	4.90E-07	lb/MMBtu	6.3E-05	2.8E-04	0.13	0.55	1.80E-07	lb/MMBtu	2.3E-05	1.0E-04	1.20E-05	lb/MMBtu	1.5E-06	6.7E-06
BOU																																											
Mod	F-401	16.7	MMBtu/hr	146,186	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0980	lb/MMBtu	1.6	7.2	0.0056	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.4	6.0	4.90E-07	lb/MMBtu	8.2E-06	3.6E-05	0.00	0.02	1.80E-07	lb/MMBtu	3.0E-06	1.3E-05	1.20E-05	lb/MMBtu	2.0E-07	8.6E-07
CFHU																																											
Oth	F-801A	10.2	MMBtu/hr	89,468	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.2	0.0490	lb/MMBtu	0.5	2.2	0.0047	lb/MMBtu	0.0	0.2	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.8	3.7	4.90E-07	lb/MMBtu	5.0E-06	2.2E-05	0.00	0.01	1.80E-07	lb/MMBtu	1.8E-06	8.1E-06	1.20E-05	lb/MMBtu	1.2E-07	5.3E-07
Oth	F-801B	10.2	MMBtu/hr	89,468	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.2	0.0490	lb/MMBtu	0.5	2.2	0.0047	lb/MMBtu	0.0	0.2	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.8	3.7	4.90E-07	lb/MMBtu	5.0E-06	2.2E-05	0.00	0.01	1.80E-07	lb/MMBtu	1.8E-06	8.1E-06	1.20E-05	lb/MMBtu	1.2E-07	5.3E-07
Oth	F-801C	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.0360	lb/MMBtu	0.0	0.0	0.0047	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0040	lb/MMBtu	0.0	0.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.00	0.00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.20E-05	lb/MMBtu	0.0E+00	0.0E+00
CRU																																											
Oth	F-101	46.4	MMBtu/hr	406,589	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0800	lb/MMBtu	3.7	16.3	0.0079	lb/MMBtu	0.4	1.6	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.8	16.7	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.02	0.07	1.80E-07	lb/MMBtu	8.4E-06	3.7E-05	1.20E-05	lb/MMBtu	5.5E-07	2.4E-06
Oth	F-102	25.0	MMBtu/hr	219,187	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0800	lb/MMBtu	2.0	8.8	0.0079	lb/MMBtu	0.2	0.9	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.1	0.4	0.082	lb/MMBtu	2.1	9.0	4.90E-07	lb/MMBtu	1.2E-05	5.4E-05	0.01	0.04	1.80E-07	lb/MMBtu	4.5E-06	2.0E-05	1.20E-05	lb/MMBtu	2.9E-07	1.3E-06
DDU																																											
Oth	WB-301	35.7	MMBtu/hr	313,034	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0346	lb/MMBtu	1.2	5.4	0.0214	lb/MMBtu	0.8	3.3	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.040	lb/MMBtu	1.4	6.3	4.90E-07	lb/MMBtu	1.8E-05	7.7E-05	0.04	0.15	1.80E-07	lb/MMBtu	6.4E-06	2.8E-05	1.20E-05	lb/MMBtu	4.2E-07	1.8E-06
Oth	WB-302	57.3	MMBtu/hr	501,791	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.4	0.0300	lb/MMBtu	1.7	7.5	0.0214	lb/MMBtu	1.2	5.4	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.2	1.0	0.040	lb/MMBtu	2.3	10.0	4.90E-07	lb/MMBtu	2.8E-05	1.2E-04	0.06	0.25	1.80E-07	lb/MMBtu	1.0E-05	4.5E-05	1.20E-05	lb/MMBtu	6.7E-07	3.0E-06
ISOM																																											
Mod	H-1	152.1	MMBtu/hr	1,332,776	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.6	0.2745	lb/MMBtu	41.8	182.9	0.0214	lb/MMBtu	3.2	14.2	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.7	0.082	lb/MMBtu	12.5	54.9	4.90E-07	lb/MMBtu	7.5E-05	3.3E-04	0.15	0.65	1.80E-07	lb/MMBtu	2.7E-05	1.2E-04	1.20E-05	lb/MMBtu	1.8E-06	7.8E-06
HU																																											
Oth	B-501	193.5	MMBtu/hr	1,694,674	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.6	0.0675	lb/MMBtu	13.1	57.2	0.0717	lb/MMBtu	13.9	60.8	0.0019	lb/MMBtu	0.4	1.6	0.0075	lb/MMBtu	1.4	6.3	0.02	lb/MMBtu	3.9	16.9	4.90E-07	lb/MMBtu	9.5E-05	4.2E-04	0.64	2.79	1.80E-07	lb/MMBtu	3.5E-05	1.5E-04	1.20E-05	lb/MMBtu	2.3E-06	1.0E-05
Utilities																																											
1SPS																																											
SD	Boiler 3	22.6	MMBtu/hr	198,018	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.1570	lb/MMBtu	3.5	15.5	0.0214	lb/MMBtu	0.5	2.1	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.2	0.7	0.049	lb/MMBtu	1.1	4.9	4.90E-07	lb/MMBtu	1.1E-05	4.9E-05	0.02	0.10	1.80E-07	lb/MMBtu	4.1E-06	1.8E-05	1.20E-05	lb/MMBtu	2.7E-07	1.2E-06
SD	Boiler 4	35.7	MMBtu/hr	312,799	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.1570	lb/MMBtu	5.6	24.6	0.0214	lb/MMBtu	0.8	3.3	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.3	1.2	0.049	lb/MMBtu	1.7	7.7	4.90E-07	lb/MMBtu	1.8E-05	7.7E-05	0.04	0.15	1.80E-07	lb/MMBtu	6.4E-06	2.8E-05	1.20E-05	lb/MMBtu	4.2E-07	1.8E-06
SD	Boiler 5	20.3	MMBtu/hr	178,181	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0930	lb/MMBtu	1.9	8.3	0.0214	lb/MMBtu	0.4	1.9	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.2	0.7	0.248	lb/MMBtu	5.0	22.1	4.90E-07	lb/MMBtu	1.0E-05	4.4E-05	0.02	0.09	1.80E-07	lb/MMBtu	3.7E-06	1.6E-05	1.20E-05	lb/MMBtu	2.4E-07	1.0E-06
SD	Boiler 6	20.0	MMBtu/hr	175,392	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0930	lb/MMBtu	1.9	8.2	0.0214	lb/MMBtu	0.4	1.9	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.1	0.7	0.248	lb/MMBtu	5.0	21.7	4.90E-07	lb/MMBtu	9.8E-06	4.3E-05	0.02	0.09	1.80E-07	lb/MMBtu	3.6E-06	1.6E-05	1.20E-05	lb/MMBtu	2.4E-07	1.0E-06
SD	Boiler 7	74.6	MMBtu/hr	653,701	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.0930	lb/MMBtu	6.9	30.4	0.0214	lb/MMBtu	1.6	7.0	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.6	2.4	0.248	lb/MMBtu	18.5	81.1	4.90E-07	lb/MMBtu	3.7E-05	1.6E-04	0.07	0.32	1.80E-07	lb/MMBtu	1.3E-05	5.9E-05	1.20E-05	lb/MMBtu	8.8E-07	3.8E-06
Lakefront																																											
SD	FBI	38,695	ons feed/yr			0.34	lb/unit feed	1.5	6.6	0.14	lb/unit feed	0.6	2.7	0.13	lb/unit feed	0.6	2.5	0.184	lb/unit feed	0.8	3.6	0.184	lb/unit feed	0.8	3

Table C.14 2001 Combustion Emissions

Process Heaters and Boilers

Code	Process Unit	Usage				VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[2]				CO				Pb				H_2SO_4 Mist		Hg				Be			
						EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
Crude and Coking																																											
11A PS																																											
Oth	H-1X	136.3	MMBtu/hr	1,193,746	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.2	0.1660	lb/MMBtu	22.6	99.1	0.0217	lb/MMBtu	3.0	12.9	0.0019	lb/MMBtu	0.3	1.1	0.0075	lb/MMBtu	0.0	4.4	0.082	lb/MMBtu	11.2	49.2	4.90E-07	lb/MMBtu	6.7E-05	2.9E-04	0.14	0.59	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	7.0E-06
Oth	H-2	32.7	MMBtu/hr	286,613	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.2	14.0	0.0217	lb/MMBtu	0.7	3.1	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.0	1.1	0.082	lb/MMBtu	2.7	11.8	4.90E-07	lb/MMBtu	1.6E-05	7.0E-05	0.03	0.14	1.80E-07	lb/MMBtu	0.0E+00	2.6E-05	1.18E-08	lb/MMBtu	0.0E+00	1.7E-06
Oth	H-3	41.3	MMBtu/hr	361,574	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.0	17.7	0.0217	lb/MMBtu	0.9	3.9	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.0	1.3	0.082	lb/MMBtu	3.4	14.9	4.90E-07	lb/MMBtu	2.0E-05	8.9E-05	0.04	0.18	1.80E-07	lb/MMBtu	0.0E+00	3.3E-05	1.18E-08	lb/MMBtu	0.0E+00	2.1E-06
11C PS																																											
Cont	H-200	155.2	MMBtu/hr	1,359,718	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.7	0.2745	lb/MMBtu	42.6	186.6	0.0217	lb/MMBtu	3.4	14.7	0.0019	lb/MMBtu	0.3	1.3	0.0075	lb/MMBtu	0.0	5.1	0.082	lb/MMBtu	12.8	56.0	4.90E-07	lb/MMBtu	7.6E-05	3.3E-04	0.15	0.68	1.80E-07	lb/MMBtu	0.0E+00	1.2E-04	1.18E-08	lb/MMBtu	0.0E+00	8.0E-06
Oth	H-300	88.2	MMBtu/hr	772,976	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.1	0.1373	lb/MMBtu	12.1	53.1	0.0217	lb/MMBtu	1.9	8.4	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.0	2.9	0.082	lb/MMBtu	7.3	31.8	4.90E-07	lb/MMBtu	4.3E-05	1.9E-04	0.09	0.38	1.80E-07	lb/MMBtu	0.0E+00	7.0E-05	1.18E-08	lb/MMBtu	0.0E+00	4.5E-06
Coker																																											
SD	H-101	36.8	MMBtu/hr	322,799	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.6	15.8	0.0217	lb/MMBtu	0.8	3.5	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.6	0.082	lb/MMBtu	3.0	13.3	4.90E-07	lb/MMBtu	1.8E-05	7.9E-05	0.04	0.16	1.80E-07	lb/MMBtu	0.0E+00	2.9E-05	1.18E-08	lb/MMBtu	0.0E+00	1.9E-06
SD	H-102	39.0	MMBtu/hr	341,664	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.8	16.7	0.0217	lb/MMBtu	0.8	3.7	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	3.2	14.1	4.90E-07	lb/MMBtu	1.9E-05	8.4E-05	0.04	0.17	1.80E-07	lb/MMBtu	0.0E+00	3.1E-05	1.18E-08	lb/MMBtu	0.0E+00	2.0E-06
SD	H-103	42.5	MMBtu/hr	372,178	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.2	18.2	0.0217	lb/MMBtu	0.9	4.0	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	3.5	15.3	4.90E-07	lb/MMBtu	2.1E-05	9.1E-05	0.04	0.19	1.80E-07	lb/MMBtu	0.0E+00	3.3E-05	1.18E-08	lb/MMBtu	0.0E+00	2.2E-06
SD	H-104	39.9	MMBtu/hr	349,682	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.9	17.1	0.0217	lb/MMBtu	0.9	3.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	3.3	14.4	4.90E-07	lb/MMBtu	2.0E-05	8.6E-05	0.04	0.17	1.80E-07	lb/MMBtu	0.0E+00	3.1E-05	1.18E-08	lb/MMBtu	0.0E+00	2.1E-06
12PS																																											
SD	H-1AN	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.2745	lb/MMBtu	0.0	0.0	0.0217	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0075	lb/MMBtu	0.0	0.0	0.082	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.00	0.00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.18E-08	lb/MMBtu	0.0E+00	0.0E+00
SD	H-1AS	90.6	MMBtu/hr	793,629	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.1	0.2745	lb/MMBtu	24.9	108.9	0.0217	lb/MMBtu	2.0	8.6	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.0	3.0	0.082	lb/MMBtu	7.5	32.7	4.90E-07	lb/MMBtu	4.4E-05	1.9E-04	0.09	0.39	1.80E-07	lb/MMBtu	0.0E+00	7.1E-05	1.18E-08	lb/MMBtu	0.0E+00	4.7E-06
SD	H-1B	138.4	MMBtu/hr	1,212,589	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.3	0.2745	lb/MMBtu	38.0	166.4	0.0217	lb/MMBtu	3.0	13.1	0.0019	lb/MMBtu	0.3	1.1	0.0075	lb/MMBtu	0.0	4.5	0.082	lb/MMBtu	11.4	49.9	4.90E-07	lb/MMBtu	6.8E-05	3.0E-04	0.14	0.60	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	7.1E-06
SD	H-2	92.1	MMBtu/hr	806,627	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.2	0.0360	lb/MMBtu	3.3	14.5	0.0217	lb/MMBtu	2.0	8.7	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.0	3.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	4.5E-05	2.0E-04	0.09	0.40	1.80E-07	lb/MMBtu	0.0E+00	7.3E-05	1.18E-08	lb/MMBtu	0.0E+00	4.7E-06
SD	H-1CN	31.5	MMBtu/hr	276,318	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	3.1	13.5	0.0217	lb/MMBtu	0.7	3.0	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.6	0.082	lb/MMBtu	2.6	11.4	4.90E-07	lb/MMBtu	1.5E-05	6.8E-05	0.03	0.14	1.80E-07	lb/MMBtu	0.0E+00	2.5E-05	1.18E-08	lb/MMBtu	0.0E+00	1.6E-06
SD	H-1CX	170.9	MMBtu/hr	1,497,306	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.0990	lb/MMBtu	16.9	74.1	0.0217	lb/MMBtu	3.7	16.2	0.0019	lb/MMBtu	0.3	1.4	0.0040	lb/MMBtu	0.0	3.0	0.082	lb/MMBtu	14.1	61.7	4.90E-07	lb/MMBtu	8.4E-05	3.7E-04	0.17	0.74	1.80E-07	lb/MMBtu	0.0E+00	1.3E-04	1.18E-08	lb/MMBtu	0.0E+00	8.8E-06
Hydroprocessing																																											
3UF																																											
SD	H-1	80.1	MMBtu/hr	701,691	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.9	0.2745	lb/MMBtu	22.0	96.3	0.0113	lb/MMBtu	0.9	4.0	0.0019	lb/MMBtu	0.1	0.7	0.0040	lb/MMBtu	0.0	1.4	0.082	lb/MMBtu	6.6	28.9	4.90E-07	lb/MMBtu	3.9E-05	1.7E-04	0.04	0.18	1.80E-07	lb/MMBtu	0.0E+00	6.3E-05	1.18E-08	lb/MMBtu	0.0E+00	4.1E-06
SD	H-2	51.0	MMBtu/hr	446,804	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.2745	lb/MMBtu	14.0	61.3	0.0113	lb/MMBtu	0.6	2.5	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.0	0.9	0.082	lb/MMBtu	4.2	18.4	4.90E-07	lb/MMBtu	2.5E-05	1.1E-04	0.03	0.12	1.80E-07	lb/MMBtu	0.0E+00	4.0E-05	1.18E-08	lb/MMBtu	0.0E+00	2.6E-06
SD	F-7	10.7	MMBtu/hr	93,730	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0980	lb/MMBtu	1.0	4.6	0.0113	lb/MMBtu	0.1	0.5	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.9	3.9	4.90E-07	lb/MMBtu	5.2E-06	2.3E-05	0.01	0.02	1.80E-07	lb/MMBtu	0.0E+00	8.4E-06	1.18E-08	lb/MMBtu	0.0E+00	5.5E-07
4UF																																											
Oth	F-1	45.7	MMBtu/hr	400,032	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.1	0.0980	lb/MMBtu	4.5	19.6	0.0086	lb/MMBtu	0.4	1.7	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.0	0.8	0.082	lb/MMBtu	3.8	16.5	4.90E-07	lb/MMBtu	2.2E-05	9.8E-05	0.02	0.08	1.80E-07	lb/MMBtu	0.0E+00	3.6E-05	1.18E-08	lb/MMBtu	0.0E+00	2.4E-06
Oth	F-8A	111.3	MMBtu/hr	975,203	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.6	0.2745	lb/MMBtu	30.6	133.9	0.0086	lb/MMBtu	1.0	4.2	0.0019	lb/MMBtu	0.2	0.9	0.0040	lb/MMBtu	0.0	2.0	0.082	lb/MMBtu	9.2	40.2	4.90E-07	lb/MMBtu	5.5E-05	2.4E-04	0.04	0.19	1.80E-07	lb/MMBtu	0.0E+00	8.8E-05	1.18E-08	lb/MMBtu	0.0E+00	5.7E-06
Oth	F-8B	109.7	MMBtu/hr	960,925	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.6	0.2745	lb/MMBtu	30.1	131.9	0.0086	lb/MMBtu	0.9	4.1	0.0019	lb/MMBtu	0.2	0.9	0.0040	lb/MMBtu	0.0	1.9	0.082	lb/MMBtu	9.0	39.6	4.90E-07	lb/MMBtu	5.4E-05	2.4E-04	0.04	0.19	1.80E-07	lb/MMBtu	0.0E+00	8.6E-05	1.18E-08	lb/MMBtu	0.0E+00	5.7E-06
Oth	F-2	249.6	MMBtu/hr	2,186,121	MMBtu/yr	0.0054	lb/MMBtu	1.3	5.9	0.1863	lb/MMBtu	46.5	203.6	0.0086	lb/MMBtu	2.1	9.4	0.0019	lb/MMBtu	0.5	2.0	0.0040	lb/MMBtu	0.0	4.4	0.082	lb/MMBtu	20.6	90.0	4.90E-07	lb/MMBtu	1.2E-04	5.4E-04	0.10	0.43	1.80E-07	lb/MMBtu	0.0E+00	2.0E-04	1.18E-08	lb/MMBtu	0.0E+00	1.3E-05
Oth	F-3	216.2	MMBtu/hr	1,893,564	MMBtu/yr	0.0054	lb/MMBtu	1.2	5.1	0.2745	lb/MMBtu	59.3	259.9	0.0086	lb/MMBtu	1.9	8.2	0.0019	lb/MMBtu	0.4	1.8	0.0040	lb/MMBtu	0.0	3.8	0.082	lb/MMBtu	17.8	78.0	4.90E-07	lb/MMBtu	1.1E-04	4.6E-04	0.09	0.37	1.80E-07	lb/MMBtu	0.0E+00	1.7E-04	1.18E-08	lb/MMBtu	0.0E+00	1.1E-05
Oth	F-4	137.2	MMBtu/hr	1,201,767	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.2	0.2745	lb/MMBtu	37.7	164.9	0.0086	lb/MMBtu	1.2	5.2	0.0019	lb/MMBtu	0.3	1.1	0.0040	lb/MMBtu	0.0	2.4	0.082	lb/MMBtu	11.3	49.5	4.90E-07	lb/MMBtu	6.7E-05	2.9E-04	0.05	0.24	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	7.1E-06
Oth	F-5	71.8	MMBtu/hr	628,632	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.0980	lb/MMBtu	7.0	30.8	0.0086	lb/MMBtu	0.6	2.7	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.0	1.3	0.082	lb/MMBtu	5.9	25.9	4.90E-07	lb/MMBtu	3.5E-05	1.5E-04	0.03	0.12	1.80E-07	lb/MMBtu	0.0E+00	5.7E-05	1.18E-08	lb/MMBtu	0.0E+00	3.7E-06
Oth	F-6	27.9	MMBtu/hr	244,133	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	2.7	12.0	0.0086	lb/MMBtu	0.2	1.1	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.0	0.5	0.082	lb/MMBtu	2.3	10.1	4.90E-07	lb/MMBtu	1.4E-05	6.0E-05	0.01	0.05	1.80E-07	lb/MMBtu	0.0E+00	2.2E-05	1.18E-08	lb/MMBtu	0.0E+00	1.4E-06
Oth	F-7	42.2	MMBtu/hr	370,088	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.1	18.1	0.0086	lb/MMBtu	0.4	1.6	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	3.5	15.2	4.90E-07	lb/MMBtu	2.1E-05	9.1E-05	0.02	0.07	1.80E-07	lb/MMBtu	0.0E+00	3.3E-05	1.18E-08	lb/MMBtu	0.0E+00	2.2E-06
ARU																																											
Oth	F-200A	138.9	MMBtu/hr	1,216,378	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.3	0.2745	lb/MMBtu	38.1	167.0	0.0217	lb/MMBtu	3.0	13.2	0.0019	lb/MMBtu	0.3	1.1	0.0040	lb/MMBtu	0.0	2.4	0.082	lb/MMBtu	11.4	50.1	4.90E-07	lb/MMBtu	6.8E-05	3.0E-04	0.14	0.60	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	7.2E-06
Oth	F-200B	147.8	MMBtu/hr	1,294,527	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.2745	lb/MMBtu	40.6	177.7	0.0217	lb/MMBtu	3.2	14.0	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.0	2.6	0.082	lb/MMBtu	12.2	53.3	4.90E-07	lb/MMBtu	7.2E-05	3.2E-04	0.15	0.64	1.80E-07	lb/MMBtu	0.0E+00	1.2E-04	1.18E-08	lb/MMBtu	0.0E+00	7.6E-06
BOU																																											
Mod	F-401	18.7	MMBtu/hr	163,632	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0980	lb/MMBtu	1.8	8.0	0.0086	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.0	0.3	0.082	lb/MMBtu	1.5	6.7	4.90E-07	lb/MMBtu	9.2E-06	4.0E-05	0.01	0.03	1.80E-07	lb/MMBtu	0.0E+00	1.5E-05	1.18E-08	lb/MMBtu	0.0E+00	9.6E-07
CFHU																																											
Oth	F-801A	17.5	MMBtu/hr	153,162	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0490	lb/MMBtu	0.9	3.8	0.0074	lb/MMBtu	0.1	0.6	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.3	0.082	lb/MMBtu	1.4	6.3	4.90E-07	lb/MMBtu	8.6E-06	3.8E-05	0.01	0.03	1.80E-07	lb/MMBtu	0.0E+00	1.4E-05	1.18E-08	lb/MMBtu	0.0E+00	9.0E-07
Oth	F-801B	17.5	MMBtu/hr	153,162	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0490	lb/MMBtu	0.9	3.8	0.0074	lb/MMBtu	0.1	0.6	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.3	0.082	lb/MMBtu	1.4	6.3	4.90E-07	lb/MMBtu	8.6E-06	3.8E-05	0.01	0.03	1.80E-07	lb/MMBtu	0.0E+00	1.4E-05	1.18E-08	lb/MMBtu	0.0E+00	9.0E-07
Oth	F-801C	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.0360	lb/MMBtu	0.0	0.0	0.0074	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0040	lb/MMBtu	0.0	0.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.00	0.00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.18E-08	lb/MMBtu	0.0E+00	0.0E+00
CRU																																											
Oth	F-101	35.4	MMBtu/hr	310,496	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0800	lb/MMBtu	2.8	12.4	0.0113	lb/MMBtu	0.4	1.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.6	0.082	lb/MMBtu	2.9	12.8	4.90E-07	lb/MMBtu	1.7E-05	7.6E-05	0.02	0.08	1.80E-07	lb/MMBtu	0.0E+00	2.8E-05	1.18E-08	lb/MMBtu	0.0E+00	1.8E-06
Oth	F-102	13.4	MMBtu/hr	117,788	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0800	lb/MMBtu	1.1	4.7	0.0113	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	1.1	4.9	4.90E-07	lb/MMBtu	6.6E-06	2.9E-05	0.01	0.03	1.80E-07	lb/MMBtu	0.0E+00	1.1E-05	1.18E-08	lb/MMBtu	0.0E+00	6.9E-07
DDU																																											
Oth	WB-301	24.6	MMBtu/hr	215,727	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0346	lb/MMBtu	0.9	3.7	0.0217	lb/MMBtu	0.5	2.3	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.0	0.4	0.040	lb/MMBtu	1.0	4.3	4.90E-07	lb/MMBtu	1.2E-05	5.3E-05	0.02	0.11	1.80E-07	lb/MMBtu	0.0E+00	1.9E-05	1.18E-08	lb/MMBtu	0.0E+00	1.3E-06
Oth	WB-302	59.5	MMBtu/hr	521,217	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.4	0.0300	lb/MMBtu	1.8	7.8	0.0217	lb/MMBtu	1.3	5.6	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.0	1.0	0.040	lb/MMBtu	2.4	10.4	4.90E-07	lb/MMBtu	2.9E-05	1.3E-04	0.06	0.26	1.80E-07	lb/MMBtu	0.0E+00	4.7E-05	1.18E-08	lb/MMBtu	0.0E+00	3.1E-06
ISOM																																											
Mod	H-1	171.4	MMBtu/hr	1,501,457	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.2745	lb/MMBtu	47.1	206.1	0.0217	lb/MMBtu	3.7	16.3	0.0019	lb/MMBtu	0.3	1.4	0.0040	lb/MMBtu	0.0	3.0	0.082	lb/MMBtu	14.1	61.8	4.90E-07	lb/MMBtu	8.4E-05	3.7E-04	0.17	0.75	1.80E-07	lb/MMBtu	0.0E+00	1.4E-04	1.18E-08	lb/MMBtu	0.0E+00	8.8E-06
HU																																											
Oth	B-501	180.2	MMBtu/hr	1,578,427	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.3	0.0675	lb/MMBtu	12.2	53.3	0.0703	lb/MMBtu	12.7	55.5	0.0019	lb/MMBtu	0.3	1.5	0.0075	lb/MMBtu	0.0	5.9	0.02	lb/MMBtu	3.6	15.8	4.90E-07	lb/MMBtu	8.8E-05	3.9E-04	0.58	2.55	1.80E-07	lb/MMBtu	0.0E+00	1.4E-04	1.18E-08	lb/MMBtu	0.0E+00	9.3E-06
Utilities																																											
1SPS																																											
SD	Boiler 3	31.4	MMBtu/hr	275,414	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.1570	lb/MMBtu	4.9	21.6	0.0217	lb/MMBtu	0.7	3.0	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.0	1.0	0.049	lb/MMBtu	1.5	6.7	4.90E-07	lb/MMBtu	1.5E-05	6.8E-05	0.03	0.14	1.80E-07	lb/MMBtu	0.0E+00	2.5E-05	1.18E-08	lb/MMBtu	0.0E+00	1.6E-06
SD	Boiler 4	41.4	MMBtu/hr	362,736	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.1570	lb/MMBtu	6.5	28.5	0.0217	lb/MMBtu	0.9	3.9	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.0	1.4	0.049	lb/MMBtu	2.0	8.9	4.90E-07	lb/MMBtu	2.0E-05	8.9E-05	0.04	0.18	1.80E-07	lb/MMBtu	0.0E+00	3.3E-05	1.18E-08	lb/MMBtu	0.0E+00	2.1E-06
SD	Boiler 5	60.5	MMBtu/hr	529,591	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.4	0.0930	lb/MMBtu	5.6	24.6	0.0217	lb/MMBtu	1.3	5.7	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.0	2.0	0.248	lb/MMBtu	15.0	65.7	4.90E-07	lb/MMBtu	3.0E-05	1.3E-04	0.06	0.26	1.80E-07	lb/MMBtu	0.0E+00	4.8E-05	1.18E-08	lb/MMBtu	0.0E+00	3.1E-06
SD	Boiler 6	17.9	MMBtu/hr	156,407	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0930	lb/MMBtu	1.7	7.3	0.0217	lb/MMBtu	0.4	1.7	0.0019	lb/MMBtu	0.0	0.1	0.0075	lb/MMBtu	0.0	0.6	0.248	lb/MMBtu	4.4	19.4	4.90E-07	lb/MMBtu	8.8E-06	3.8E-05	0.02	0.08	1.80E-07	lb/MMBtu	0.0E+00	1.4E-05	1.18E-08	lb/MMBtu	0.0E+00	9.2E-07
SD	Boiler 7	75.9	MMBtu/hr	664,748	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.0930	lb/MMBtu	7.1	30.9	0.0217	lb/MMBtu	1.6	7.2	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.0	2.5	0.248	lb/MMBtu	18.8	82.4	4.90E-07	lb/MMBtu	3.7E-05	1.6E-04	0.08	0.33	1.80E-07	lb/MMBtu	0.0E+00	6.0E-05	1.18E-08	lb/MMBtu	0.0E+00	3.9E-06
Lakefront																																											
SD	FBI	46,632	tons feed			0.34	lb/unit feed	1.8	7.9	0.14	lb/unit feed	0.7	3.3	0.13	lb/unit feed	0.7	3.0	0.184	lb/unit feed	1.0	4.3	0.184	lb/unit feed	0.98	4.3

Table C.15. 2002 Combustion Emissions

Process Heaters and Boilers

Code	Process Unit	Usage				VOC				NO_x				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[2]				CO				Pb				H_2SO_4 Mist		Hg				Be			
						EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
Crude and Coking																																											
11A PS																																											
Oth	H-1X	113.3	MMBtu/hr	992,610	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.7	0.1660	lb/MMBtu	18.8	82.4	0.0210	lb/MMBtu	2.4	10.4	0.0019	lb/MMBtu	0.2	0.9	0.0075	lb/MMBtu	0.0	3.7	0.082	lb/MMBtu	9.3	40.9	4.90E-07	lb/MMBtu	5.6E-05	2.4E-04	0.11	0.48	1.80E-07	lb/MMBtu	0.0E+00	8.9E-05	1.18E-08	lb/MMBtu	0.0E+00	5.8E-06
Oth	H-2	22.5	MMBtu/hr	196,812	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0980	lb/MMBtu	2.2	9.6	0.0210	lb/MMBtu	0.5	2.1	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	1.9	8.1	4.90E-07	lb/MMBtu	1.1E-05	4.8E-05	0.02	0.09	1.80E-07	lb/MMBtu	0.0E+00	1.8E-05	1.18E-08	lb/MMBtu	0.0E+00	1.2E-06
Oth	H-3	42.2	MMBtu/hr	369,799	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.1	18.1	0.0210	lb/MMBtu	0.9	3.9	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.0	1.4	0.082	lb/MMBtu	3.5	15.2	4.90E-07	lb/MMBtu	2.1E-05	9.1E-05	0.04	0.18	1.80E-07	lb/MMBtu	0.0E+00	3.3E-05	1.18E-08	lb/MMBtu	0.0E+00	2.2E-06
11C PS																																											
Cont	H-200	160.0	MMBtu/hr	1,401,452	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.8	0.2745	lb/MMBtu	43.9	192.4	0.0210	lb/MMBtu	3.4	14.7	0.0019	lb/MMBtu	0.3	1.3	0.0075	lb/MMBtu	0.0	5.2	0.082	lb/MMBtu	13.2	57.7	4.90E-07	lb/MMBtu	7.8E-05	3.4E-04	0.15	0.67	1.80E-07	lb/MMBtu	0.0E+00	1.3E-04	1.18E-08	lb/MMBtu	0.0E+00	8.2E-06
Oth	H-300	77.3	MMBtu/hr	677,564	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.1373	lb/MMBtu	10.6	46.5	0.0210	lb/MMBtu	1.6	7.1	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.0	2.5	0.082	lb/MMBtu	6.4	27.9	4.90E-07	lb/MMBtu	3.8E-05	1.7E-04	0.07	0.33	1.80E-07	lb/MMBtu	0.0E+00	6.1E-05	1.18E-08	lb/MMBtu	0.0E+00	4.0E-06
Coker																																											
SD	H-101	38.4	MMBtu/hr	336,228	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.8	16.5	0.0210	lb/MMBtu	0.8	3.5	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	3.2	13.8	4.90E-07	lb/MMBtu	1.9E-05	8.2E-05	0.04	0.16	1.80E-07	lb/MMBtu	0.0E+00	3.0E-05	1.18E-08	lb/MMBtu	0.0E+00	2.0E-06
SD	H-102	36.6	MMBtu/hr	320,323	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.6	15.7	0.0210	lb/MMBtu	0.8	3.4	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.6	0.082	lb/MMBtu	3.0	13.2	4.90E-07	lb/MMBtu	1.8E-05	7.9E-05	0.04	0.15	1.80E-07	lb/MMBtu	0.0E+00	2.9E-05	1.18E-08	lb/MMBtu	0.0E+00	1.9E-06
SD	H-103	40.9	MMBtu/hr	358,069	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.0	17.6	0.0210	lb/MMBtu	0.9	3.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.7	0.082	lb/MMBtu	3.4	14.7	4.90E-07	lb/MMBtu	2.0E-05	8.8E-05	0.04	0.17	1.80E-07	lb/MMBtu	0.0E+00	3.2E-05	1.18E-08	lb/MMBtu	0.0E+00	2.1E-06
SD	H-104	36.6	MMBtu/hr	320,359	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.6	15.7	0.0210	lb/MMBtu	0.8	3.4	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.6	0.082	lb/MMBtu	3.0	13.2	4.90E-07	lb/MMBtu	1.8E-05	7.9E-05	0.04	0.15	1.80E-07	lb/MMBtu	0.0E+00	2.9E-05	1.18E-08	lb/MMBtu	0.0E+00	1.9E-06
12PS																																											
SD	H-1AN	82.3	MMBtu/hr	721,198	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.9	0.2745	lb/MMBtu	22.6	99.0	0.0210	lb/MMBtu	1.7	7.6	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.0	2.7	0.082	lb/MMBtu	6.8	29.7	4.90E-07	lb/MMBtu	4.0E-05	1.8E-04	0.08	0.35	1.80E-07	lb/MMBtu	0.0E+00	6.5E-05	1.18E-08	lb/MMBtu	0.0E+00	4.2E-06
SD	H-1AS	65.0	MMBtu/hr	569,232	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.5	0.2745	lb/MMBtu	17.8	78.1	0.0210	lb/MMBtu	1.4	6.0	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.0	2.1	0.082	lb/MMBtu	5.4	23.4	4.90E-07	lb/MMBtu	3.2E-05	1.4E-04	0.06	0.27	1.80E-07	lb/MMBtu	0.0E+00	5.1E-05	1.18E-08	lb/MMBtu	0.0E+00	3.3E-06
SD	H-1B	191.5	MMBtu/hr	1,677,910	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.5	0.2745	lb/MMBtu	52.6	230.3	0.0210	lb/MMBtu	4.0	17.6	0.0019	lb/MMBtu	0.4	1.6	0.0075	lb/MMBtu	0.0	6.3	0.082	lb/MMBtu	15.8	69.1	4.90E-07	lb/MMBtu	9.4E-05	4.1E-04	0.18	0.81	1.80E-07	lb/MMBtu	0.0E+00	1.5E-04	1.18E-08	lb/MMBtu	0.0E+00	9.9E-06
SD	H-2	131.7	MMBtu/hr	1,153,304	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.1	0.0360	lb/MMBtu	4.7	20.8	0.0210	lb/MMBtu	2.8	12.1	0.0019	lb/MMBtu	0.2	1.1	0.0075	lb/MMBtu	0.0	4.3	0.0001	lb/MMBtu	0.0	0.1	4.90E-07	lb/MMBtu	6.5E-05	2.8E-04	0.13	0.55	1.80E-07	lb/MMBtu	0.0E+00	1.0E-04	1.18E-08	lb/MMBtu	0.0E+00	6.8E-06
SD	H-1CN	55.5	MMBtu/hr	485,870	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.3	0.0980	lb/MMBtu	5.4	23.8	0.0210	lb/MMBtu	1.2	5.1	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.0	1.0	0.082	lb/MMBtu	4.6	20.0	4.90E-07	lb/MMBtu	2.7E-05	1.2E-04	0.05	0.23	1.80E-07	lb/MMBtu	0.0E+00	4.4E-05	1.18E-08	lb/MMBtu	0.0E+00	2.9E-06
SD	H-1CX	262.7	MMBtu/hr	2,301,611	MMBtu/yr	0.0054	lb/MMBtu	1.4	6.2	0.0990	lb/MMBtu	26.0	113.9	0.0210	lb/MMBtu	5.5	24.1	0.0019	lb/MMBtu	0.5	2.1	0.0040	lb/MMBtu	0.0	4.0	0.082	lb/MMBtu	21.6	94.8	4.90E-07	lb/MMBtu	1.3E-04	5.6E-04	0.25	1.11	1.80E-07	lb/MMBtu	0.0E+00	2.1E-04	1.18E-08	lb/MMBtu	0.0E+00	1.4E-05
Hydroprocessing																																											
3UF																																											
SD	H-1	86.0	MMBtu/hr	753,382	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.0	0.2745	lb/MMBtu	23.6	103.4	0.0074	lb/MMBtu	0.6	2.8	0.0019	lb/MMBtu	0.2	0.7	0.0040	lb/MMBtu	0.0	1.5	0.082	lb/MMBtu	7.1	31.0	4.90E-07	lb/MMBtu	4.2E-05	1.8E-04	0.03	0.13	1.80E-07	lb/MMBtu	0.0E+00	6.8E-05	1.18E-08	lb/MMBtu	0.0E+00	4.4E-06
SD	H-2	91.4	MMBtu/hr	800,817	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.2	0.2745	lb/MMBtu	25.1	109.9	0.0074	lb/MMBtu	0.7	3.0	0.0019	lb/MMBtu	0.2	0.7	0.0040	lb/MMBtu	0.0	1.6	0.082	lb/MMBtu	7.5	33.0	4.90E-07	lb/MMBtu	4.5E-05	2.0E-04	0.03	0.14	1.80E-07	lb/MMBtu	0.0E+00	7.2E-05	1.18E-08	lb/MMBtu	0.0E+00	4.7E-06
SD	F-7	14.3	MMBtu/hr	125,616	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0980	lb/MMBtu	1.4	6.2	0.0074	lb/MMBtu	0.1	0.5	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.3	0.082	lb/MMBtu	1.2	5.2	4.90E-07	lb/MMBtu	7.0E-06	3.1E-05	0.00	0.02	1.80E-07	lb/MMBtu	0.0E+00	1.1E-05	1.18E-08	lb/MMBtu	0.0E+00	7.4E-07
4UF																																											
Oth	F-1	31.7	MMBtu/hr	277,335	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	3.1	13.6	0.0090	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.0	0.6	0.082	lb/MMBtu	2.6	11.4	4.90E-07	lb/MMBtu	1.6E-05	6.8E-05	0.01	0.06	1.80E-07	lb/MMBtu	0.0E+00	2.5E-05	1.18E-08	lb/MMBtu	0.0E+00	1.6E-06
Oth	F-8A	71.9	MMBtu/hr	629,825	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.2745	lb/MMBtu	19.7	86.4	0.0090	lb/MMBtu	0.6	2.8	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.0	1.3	0.082	lb/MMBtu	5.9	25.9	4.90E-07	lb/MMBtu	3.5E-05	1.5E-04	0.03	0.13	1.80E-07	lb/MMBtu	0.0E+00	5.7E-05	1.18E-08	lb/MMBtu	0.0E+00	3.7E-06
Oth	F-8B	67.5	MMBtu/hr	591,622	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.6	0.2745	lb/MMBtu	18.5	81.2	0.0090	lb/MMBtu	0.6	2.7	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.0	1.2	0.082	lb/MMBtu	5.6	24.4	4.90E-07	lb/MMBtu	3.3E-05	1.5E-04	0.03	0.12	1.80E-07	lb/MMBtu	0.0E+00	5.3E-05	1.18E-08	lb/MMBtu	0.0E+00	3.5E-06
Oth	F-2	164.4	MMBtu/hr	1,439,968	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.9	0.1863	lb/MMBtu	30.6	134.1	0.0090	lb/MMBtu	1.5	6.5	0.0019	lb/MMBtu	0.3	1.3	0.0040	lb/MMBtu	0.0	2.9	0.082	lb/MMBtu	13.5	59.3	4.90E-07	lb/MMBtu	8.1E-05	3.5E-04	0.07	0.30	1.80E-07	lb/MMBtu	0.0E+00	1.3E-04	1.18E-08	lb/MMBtu	0.0E+00	8.5E-06
Oth	F-3	138.9	MMBtu/hr	1,216,619	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.3	0.2745	lb/MMBtu	38.1	167.0	0.0090	lb/MMBtu	1.2	5.5	0.0019	lb/MMBtu	0.3	1.1	0.0040	lb/MMBtu	0.0	2.4	0.082	lb/MMBtu	11.4	50.1	4.90E-07	lb/MMBtu	6.8E-05	3.0E-04	0.06	0.25	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	7.2E-06
Oth	F-4	87.3	MMBtu/hr	764,321	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.1	0.2745	lb/MMBtu	24.0	104.9	0.0090	lb/MMBtu	0.8	3.4	0.0019	lb/MMBtu	0.2	0.7	0.0040	lb/MMBtu	0.0	1.5	0.082	lb/MMBtu	7.2	31.5	4.90E-07	lb/MMBtu	4.3E-05	1.9E-04	0.04	0.16	1.80E-07	lb/MMBtu	0.0E+00	6.9E-05	1.18E-08	lb/MMBtu	0.0E+00	4.5E-06
Oth	F-5	45.0	MMBtu/hr	394,172	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.1	0.0980	lb/MMBtu	4.4	19.3	0.0090	lb/MMBtu	0.4	1.8	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.0	0.8	0.082	lb/MMBtu	3.7	16.2	4.90E-07	lb/MMBtu	2.2E-05	9.7E-05	0.02	0.08	1.80E-07	lb/MMBtu	0.0E+00	3.5E-05	1.18E-08	lb/MMBtu	0.0E+00	2.3E-06
Oth	F-6	29.5	MMBtu/hr	258,845	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	2.9	12.7	0.0090	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.0	0.5	0.082	lb/MMBtu	2.4	10.7	4.90E-07	lb/MMBtu	1.4E-05	6.3E-05	0.01	0.05	1.80E-07	lb/MMBtu	0.0E+00	2.3E-05	1.18E-08	lb/MMBtu	0.0E+00	1.5E-06
Oth	F-7	28.2	MMBtu/hr	246,826	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	2.8	12.1	0.0090	lb/MMBtu	0.3	1.1	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.0	0.5	0.082	lb/MMBtu	2.3	10.2	4.90E-07	lb/MMBtu	1.4E-05	6.0E-05	0.01	0.05	1.80E-07	lb/MMBtu	0.0E+00	2.2E-05	1.18E-08	lb/MMBtu	0.0E+00	1.5E-06
ARU																																											
Oth	F-200A	125.5	MMBtu/hr	1,099,020	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.0	0.2745	lb/MMBtu	34.4	150.8	0.0210	lb/MMBtu	2.6	11.5	0.0019	lb/MMBtu	0.2	1.0	0.0040	lb/MMBtu	0.0	2.2	0.082	lb/MMBtu	10.3	45.3	4.90E-07	lb/MMBtu	6.1E-05	2.7E-04	0.12	0.53	1.80E-07	lb/MMBtu	0.0E+00	9.9E-05	1.18E-08	lb/MMBtu	0.0E+00	6.5E-06
Oth	F-200B	134.2	MMBtu/hr	1,175,552	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.2	0.2745	lb/MMBtu	36.8	161.4	0.0210	lb/MMBtu	2.8	12.3	0.0019	lb/MMBtu	0.2	1.1	0.0040	lb/MMBtu	0.0	2.4	0.082	lb/MMBtu	11.1	48.4	4.90E-07	lb/MMBtu	6.6E-05	2.9E-04	0.13	0.57	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	6.9E-06
BOU																																											
Mod	F-401	8.9	MMBtu/hr	78,099	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.2	0.0980	lb/MMBtu	0.9	3.8	0.0090	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.7	3.2	4.90E-07	lb/MMBtu	4.4E-06	1.9E-05	0.00	0.02	1.80E-07	lb/MMBtu	0.0E+00	7.0E-06	1.18E-08	lb/MMBtu	0.0E+00	4.6E-07
CFHU																																											
Oth	F-801A	15.7	MMBtu/hr	137,553	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0490	lb/MMBtu	0.8	3.4	0.0128	lb/MMBtu	0.2	0.9	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.3	0.082	lb/MMBtu	1.3	5.7	4.90E-07	lb/MMBtu	7.7E-06	3.4E-05	0.01	0.04	1.80E-07	lb/MMBtu	0.0E+00	1.2E-05	1.18E-08	lb/MMBtu	0.0E+00	8.1E-07
Oth	F-801B	14.0	MMBtu/hr	123,008	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0490	lb/MMBtu	0.7	3.0	0.0128	lb/MMBtu	0.2	0.8	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	1.2	5.1	4.90E-07	lb/MMBtu	6.9E-06	3.0E-05	0.01	0.04	1.80E-07	lb/MMBtu	0.0E+00	1.1E-05	1.18E-08	lb/MMBtu	0.0E+00	7.2E-07
Oth	F-801C	0.0	MMBtu/hr	0	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.0360	lb/MMBtu	0.0	0.0	0.0128	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0040	lb/MMBtu	0.0	0.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	0.0E+00	0.0E+00	0.00	0.00	1.80E-07	lb/MMBtu	0.0E+00	0.0E+00	1.18E-08	lb/MMBtu	0.0E+00	0.0E+00
CRU																																											
Oth	F-101	22.1	MMBtu/hr	194,026	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.5	0.0800	lb/MMBtu	1.8	7.8	0.0074	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.0	0.4	0.082	lb/MMBtu	1.8	8.0	4.90E-07	lb/MMBtu	1.1E-05	4.8E-05	0.01	0.03	1.80E-07	lb/MMBtu	0.0E+00	1.7E-05	1.18E-08	lb/MMBtu	0.0E+00	1.1E-06
Oth	F-102	16.5	MMBtu/hr	144,932	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0800	lb/MMBtu	1.3	5.8	0.0074	lb/MMBtu	0.1	0.5	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.3	0.082	lb/MMBtu	1.4	6.0	4.90E-07	lb/MMBtu	8.1E-06	3.6E-05	0.01	0.02	1.80E-07	lb/MMBtu	0.0E+00	1.3E-05	1.18E-08	lb/MMBtu	0.0E+00	8.5E-07
DDU																																											
Oth	WB-301	28.1	MMBtu/hr	245,999	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0346	lb/MMBtu	1.0	4.3	0.0210	lb/MMBtu	0.6	2.6	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.0	0.5	0.040	lb/MMBtu	1.1	4.9	4.90E-07	lb/MMBtu	1.4E-05	6.0E-05	0.03	0.12	1.80E-07	lb/MMBtu	0.0E+00	2.2E-05	1.18E-08	lb/MMBtu	0.0E+00	1.4E-06
Oth	WB-302	61.6	MMBtu/hr	539,467	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.5	0.0300	lb/MMBtu	1.8	8.1	0.0210	lb/MMBtu	1.3	5.7	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.0	1.1	0.040	lb/MMBtu	2.5	10.8	4.90E-07	lb/MMBtu	3.0E-05	1.3E-04	0.06	0.26	1.80E-07	lb/MMBtu	0.0E+00	4.9E-05	1.18E-08	lb/MMBtu	0.0E+00	3.2E-06
ISOM																																											
Mod	H-1	138.0	MMBtu/hr	1,208,953	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.3	0.2745	lb/MMBtu	37.9	165.9	0.0210	lb/MMBtu	2.9	12.7	0.0019	lb/MMBtu	0.3	1.1	0.0040	lb/MMBtu	0.0	2.4	0.082	lb/MMBtu	11.4	49.8	4.90E-07	lb/MMBtu	6.8E-05	3.0E-04	0.13	0.58	1.80E-07	lb/MMBtu	0.0E+00	1.1E-04	1.18E-08	lb/MMBtu	0.0E+00	7.1E-06
HU																																											
Oth	B-501	155.4	MMBtu/hr	1,361,598	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.7	0.0675	lb/MMBtu	10.5	46.0	0.0672	lb/MMBtu	10.4	45.7	0.0019	lb/MMBtu	0.3	1.3	0.0075	lb/MMBtu	0.0	5.1	0.02	lb/MMBtu	3.1	13.6	4.90E-07	lb/MMBtu	7.6E-05	3.3E-04	0.48	2.10	1.80E-07	lb/MMBtu	0.0E+00	1.2E-04	1.18E-08	lb/MMBtu	0.0E+00	8.0E-06
Utilities																																											
1SPS																																											
SD	Boiler 3	63.8	MMBtu/hr	558,791	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.5	0.1570	lb/MMBtu	10.0	43.9	0.0210	lb/MMBtu	1.3	5.9	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.0	2.1	0.049	lb/MMBtu	3.1	13.7	4.90E-07	lb/MMBtu	3.1E-05	1.4E-04	0.06	0.27	1.80E-07	lb/MMBtu	0.0E+00	5.0E-05	1.18E-08	lb/MMBtu	0.0E+00	3.3E-06
SD	Boiler 4	65.0	MMBtu/hr	569,196	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.5	0.1570	lb/MMBtu	10.2	44.7	0.0210	lb/MMBtu	1.4	6.0	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.0	2.1	0.049	lb/MMBtu	3.2	13.9	4.90E-07	lb/MMBtu	3.2E-05	1.4E-04	0.06	0.27	1.80E-07	lb/MMBtu	0.0E+00	5.1E-05	1.18E-08	lb/MMBtu	0.0E+00	3.3E-06
SD	Boiler 5	31.2	MMBtu/hr	273,601	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0930	lb/MMBtu	2.9	12.7	0.0210	lb/MMBtu	0.7	2.9	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.0	1.0	0.248	lb/MMBtu	7.7	33.9	4.90E-07	lb/MMBtu	1.5E-05	6.7E-05	0.03	0.13	1.80E-07	lb/MMBtu	0.0E+00	2.5E-05	1.18E-08	lb/MMBtu	0.0E+00	1.6E-06
SD	Boiler 6	25.8	MMBtu/hr	225,690	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0930	lb/MMBtu	2.4	10.5	0.0210	lb/MMBtu	0.5	2.4	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.0	0.8	0.248	lb/MMBtu	6.4	28.0	4.90E-07	lb/MMBtu	1.3E-05	5.5E-05	0.02	0.11	1.80E-07	lb/MMBtu	0.0E+00	2.0E-05	1.18E-08	lb/MMBtu	0.0E+00	1.3E-06
SD	Boiler 7	47.8	MMBtu/hr	418,794	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0930	lb/MMBtu	4.4	19.5	0.0210	lb/MMBtu	1.0	4.4	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.0	1.6	0.248	lb/MMBtu	11.9	51.9	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.05	0.20	1.80E-07	lb/MMBtu	0.0E+00	3.8E-05	1.18E-08	lb/MMBtu	0.0E+00	2.5E-06
Lakefront																																											
SD	FBI	17	MMGal/yr	86,369	tons feed	0.0305	lb/unit feed	0.3	1.3	4.7574	lb/Mgal feed	3.7	16.4	0.0093	lb/Mgal feed	0.0	0.0	0.0255	lb/Mgal feed	0.0	0.1	0.0255

Table C.16. 2003 Combustion Emissions

Process Heaters and Boilers

Code	Process Unit	Usage				VOC				NO_x				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[2]				CO				Pb				H_2SO_4 Mist		Hg				Be			
						EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
Crude and Coking																																											
11A PS																																											
Oth	H-1X	148.1	MMBtu/hr	1,297,532	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.1660	lb/MMBtu	24.6	107.7	0.0200	lb/MMBtu	3.0	13.0	0.0019	lb/MMBtu	0.3	1.2	0.0075	lb/MMBtu	1.1	4.8	0.082	lb/MMBtu	12.2	53.4	4.90E-07	lb/MMBtu	7.3E-05	3.2E-04	0.14	0.60	1.80E-07	lb/MMBtu	2.7E-05	1.2E-04	1.18E-08	lb/MMBtu	1.7E-06	7.6E-06
Oth	H-2	24.2	MMBtu/hr	211,688	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0980	lb/MMBtu	2.4	10.4	0.0200	lb/MMBtu	0.5	2.1	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	2.0	8.7	4.90E-07	lb/MMBtu	1.2E-05	5.2E-05	0.02	0.10	1.80E-07	lb/MMBtu	4.3E-06	1.9E-05	1.18E-08	lb/MMBtu	2.8E-07	1.2E-06
Oth	H-3	36.9	MMBtu/hr	322,837	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.6	15.8	0.0200	lb/MMBtu	0.7	3.2	0.0019	lb/MMBtu	0.1	0.3	0.0075	lb/MMBtu	0.3	1.2	0.082	lb/MMBtu	3.0	13.3	4.90E-07	lb/MMBtu	1.8E-05	7.9E-05	0.03	0.15	1.80E-07	lb/MMBtu	6.6E-06	2.9E-05	1.18E-08	lb/MMBtu	4.3E-07	1.9E-06
11C PS																																											
Cont	H-200	91.2	MMBtu/hr	798,797	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.2	0.2745	lb/MMBtu	25.0	109.6	0.0200	lb/MMBtu	1.8	8.0	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.7	3.0	0.082	lb/MMBtu	7.5	32.9	4.90E-07	lb/MMBtu	4.5E-05	2.0E-04	0.08	0.37	1.80E-07	lb/MMBtu	1.6E-05	7.2E-05	1.18E-08	lb/MMBtu	1.1E-06	4.7E-06
Oth	H-300	74.4	MMBtu/hr	651,599	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.1373	lb/MMBtu	10.2	44.7	0.0200	lb/MMBtu	1.5	6.5	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.6	2.4	0.082	lb/MMBtu	6.1	26.8	4.90E-07	lb/MMBtu	3.6E-05	1.6E-04	0.07	0.30	1.80E-07	lb/MMBtu	1.3E-05	5.9E-05	1.18E-08	lb/MMBtu	8.8E-07	3.8E-06
Coker																																											
SD	H-101	39.6	MMBtu/hr	346,501	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.9	17.0	0.0200	lb/MMBtu	0.8	3.5	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.3	14.3	4.90E-07	lb/MMBtu	1.9E-05	8.5E-05	0.04	0.16	1.80E-07	lb/MMBtu	7.1E-06	3.1E-05	1.18E-08	lb/MMBtu	4.7E-07	2.0E-06
SD	H-102	31.4	MMBtu/hr	274,871	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	3.1	13.5	0.0200	lb/MMBtu	0.6	2.7	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.6	11.3	4.90E-07	lb/MMBtu	1.5E-05	6.7E-05	0.03	0.13	1.80E-07	lb/MMBtu	5.6E-06	2.5E-05	1.18E-08	lb/MMBtu	3.7E-07	1.6E-06
SD	H-103	33.7	MMBtu/hr	294,923	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.3	14.5	0.0200	lb/MMBtu	0.7	2.9	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.8	12.1	4.90E-07	lb/MMBtu	1.7E-05	7.2E-05	0.03	0.14	1.80E-07	lb/MMBtu	6.1E-06	2.7E-05	1.18E-08	lb/MMBtu	4.0E-07	1.7E-06
SD	H-104	31.2	MMBtu/hr	273,055	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	3.1	13.4	0.0200	lb/MMBtu	0.6	2.7	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.6	11.2	4.90E-07	lb/MMBtu	1.5E-05	6.7E-05	0.03	0.13	1.80E-07	lb/MMBtu	5.6E-06	2.5E-05	1.18E-08	lb/MMBtu	3.7E-07	1.6E-06
12PS																																											
SD	H-1AN	81.0	MMBtu/hr	709,998	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.9	0.2745	lb/MMBtu	22.2	97.5	0.0200	lb/MMBtu	1.6	7.1	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.6	2.6	0.082	lb/MMBtu	6.7	29.2	4.90E-07	lb/MMBtu	4.0E-05	1.7E-04	0.07	0.33	1.80E-07	lb/MMBtu	1.5E-05	6.4E-05	1.18E-08	lb/MMBtu	9.5E-07	4.2E-06
SD	H-1AS	61.0	MMBtu/hr	534,293	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.4	0.2745	lb/MMBtu	16.7	73.3	0.0200	lb/MMBtu	1.2	5.3	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.5	2.0	0.082	lb/MMBtu	5.0	22.0	4.90E-07	lb/MMBtu	3.0E-05	1.3E-04	0.06	0.25	1.80E-07	lb/MMBtu	1.1E-05	4.8E-05	1.18E-08	lb/MMBtu	7.2E-07	3.1E-06
SD	H-1B	170.2	MMBtu/hr	1,490,723	MMBtu/yr	0.0054	lb/MMBtu	0.9	4.0	0.2745	lb/MMBtu	46.7	204.6	0.0200	lb/MMBtu	3.4	14.9	0.0019	lb/MMBtu	0.3	1.4	0.0075	lb/MMBtu	1.3	5.6	0.082	lb/MMBtu	14.0	61.4	4.90E-07	lb/MMBtu	8.3E-05	3.7E-04	0.16	0.68	1.80E-07	lb/MMBtu	3.1E-05	1.3E-04	1.18E-08	lb/MMBtu	2.0E-06	8.8E-06
SD	H-2	129.0	MMBtu/hr	1,130,066	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.0	0.0360	lb/MMBtu	4.6	20.3	0.0200	lb/MMBtu	2.6	11.3	0.0019	lb/MMBtu	0.2	1.1	0.0075	lb/MMBtu	1.0	4.2	0.0001	lb/MMBtu	0.0	0.1	4.90E-07	lb/MMBtu	6.3E-05	2.8E-04	0.12	0.52	1.80E-07	lb/MMBtu	2.3E-05	1.0E-04	1.18E-08	lb/MMBtu	1.5E-06	6.6E-06
SD	H-1CN	46.1	MMBtu/hr	403,538	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.1	0.0980	lb/MMBtu	4.5	19.8	0.0200	lb/MMBtu	0.9	4.0	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.8	16.6	4.90E-07	lb/MMBtu	2.3E-05	9.9E-05	0.04	0.19	1.80E-07	lb/MMBtu	8.3E-06	3.6E-05	1.18E-08	lb/MMBtu	5.4E-07	2.4E-06
SD	H-1CX	248.3	MMBtu/hr	2,174,836	MMBtu/yr	0.0054	lb/MMBtu	1.3	5.9	0.0990	lb/MMBtu	24.6	107.7	0.0200	lb/MMBtu	5.0	21.7	0.0019	lb/MMBtu	0.5	2.0	0.0040	lb/MMBtu	0.9	4.0	0.082	lb/MMBtu	20.4	89.6	4.90E-07	lb/MMBtu	1.2E-04	5.3E-04	0.23	1.00	1.80E-07	lb/MMBtu	4.5E-05	2.0E-04	1.18E-08	lb/MMBtu	2.9E-06	1.3E-05
Hydroprocessing																																											
3UF																																											
SD	H-1	87.4	MMBtu/hr	765,623	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.1	0.2745	lb/MMBtu	24.0	105.1	0.0069	lb/MMBtu	0.6	2.6	0.0019	lb/MMBtu	0.2	0.7	0.0040	lb/MMBtu	0.3	1.5	0.082	lb/MMBtu	7.2	31.5	4.90E-07	lb/MMBtu	4.3E-05	1.9E-04	0.03	0.12	1.80E-07	lb/MMBtu	1.6E-05	6.9E-05	1.18E-08	lb/MMBtu	1.0E-06	4.5E-06
SD	H-2	92.8	MMBtu/hr	812,955	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.2	0.2745	lb/MMBtu	25.5	111.6	0.0069	lb/MMBtu	0.6	2.8	0.0019	lb/MMBtu	0.2	0.8	0.0040	lb/MMBtu	0.4	1.6	0.082	lb/MMBtu	7.6	33.5	4.90E-07	lb/MMBtu	4.5E-05	2.0E-04	0.03	0.13	1.80E-07	lb/MMBtu	1.7E-05	7.3E-05	1.18E-08	lb/MMBtu	1.1E-06	4.8E-06
SD	F-7	14.8	MMBtu/hr	129,957	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0980	lb/MMBtu	1.5	6.4	0.0069	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.2	5.4	4.90E-07	lb/MMBtu	7.3E-06	3.2E-05	0.00	0.02	1.80E-07	lb/MMBtu	2.7E-06	1.2E-05	1.18E-08	lb/MMBtu	1.7E-07	7.6E-07
4UF																																											
Oth	F-1	34.5	MMBtu/hr	302,140	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.4	14.8	0.0075	lb/MMBtu	0.3	1.1	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.8	12.4	4.90E-07	lb/MMBtu	1.7E-05	7.4E-05	0.01	0.05	1.80E-07	lb/MMBtu	6.2E-06	2.7E-05	1.18E-08	lb/MMBtu	4.1E-07	1.8E-06
Oth	F-8A	74.1	MMBtu/hr	649,097	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.2745	lb/MMBtu	20.3	89.1	0.0075	lb/MMBtu	0.6	2.4	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.3	1.3	0.082	lb/MMBtu	6.1	26.7	4.90E-07	lb/MMBtu	3.6E-05	1.6E-04	0.03	0.11	1.80E-07	lb/MMBtu	1.3E-05	5.8E-05	1.18E-08	lb/MMBtu	8.7E-07	3.8E-06
Oth	F-8B	70.6	MMBtu/hr	618,527	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.2745	lb/MMBtu	19.4	84.9	0.0075	lb/MMBtu	0.5	2.3	0.0019	lb/MMBtu	0.1	0.6	0.0040	lb/MMBtu	0.3	1.2	0.082	lb/MMBtu	5.8	25.5	4.90E-07	lb/MMBtu	3.5E-05	1.5E-04	0.02	0.11	1.80E-07	lb/MMBtu	1.3E-05	5.6E-05	1.18E-08	lb/MMBtu	8.3E-07	3.6E-06
Oth	F-2	187.3	MMBtu/hr	1,640,317	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.4	0.1863	lb/MMBtu	34.9	152.8	0.0075	lb/MMBtu	1.4	6.1	0.0019	lb/MMBtu	0.3	1.5	0.0040	lb/MMBtu	0.7	3.3	0.082	lb/MMBtu	15.4	67.5	4.90E-07	lb/MMBtu	9.2E-05	4.0E-04	0.06	0.28	1.80E-07	lb/MMBtu	3.4E-05	1.5E-04	1.18E-08	lb/MMBtu	2.2E-06	9.6E-06
Oth	F-3	162.7	MMBtu/hr	1,425,543	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.8	0.2745	lb/MMBtu	44.7	195.7	0.0075	lb/MMBtu	1.2	5.3	0.0019	lb/MMBtu	0.3	1.3	0.0040	lb/MMBtu	0.7	2.9	0.082	lb/MMBtu	13.4	58.7	4.90E-07	lb/MMBtu	8.0E-05	3.5E-04	0.06	0.24	1.80E-07	lb/MMBtu	2.9E-05	1.3E-04	1.18E-08	lb/MMBtu	1.9E-06	8.4E-06
Oth	F-4	87.3	MMBtu/hr	764,368	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.1	0.2745	lb/MMBtu	24.0	104.9	0.0075	lb/MMBtu	0.7	2.9	0.0019	lb/MMBtu	0.2	0.7	0.0040	lb/MMBtu	0.3	1.5	0.082	lb/MMBtu	7.2	31.5	4.90E-07	lb/MMBtu	4.3E-05	1.9E-04	0.03	0.13	1.80E-07	lb/MMBtu	1.6E-05	6.9E-05	1.18E-08	lb/MMBtu	1.0E-06	4.5E-06
Oth	F-5	47.0	MMBtu/hr	411,990	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0980	lb/MMBtu	4.6	20.2	0.0075	lb/MMBtu	0.4	1.5	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.9	17.0	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.02	0.07	1.80E-07	lb/MMBtu	8.5E-06	3.7E-05	1.18E-08	lb/MMBtu	5.5E-07	2.4E-06
Oth	F-6	29.0	MMBtu/hr	254,070	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	2.8	12.5	0.0075	lb/MMBtu	0.2	1.0	0.0019	lb/MMBtu	0.1	0.2	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.4	10.5	4.90E-07	lb/MMBtu	1.4E-05	6.2E-05	0.01	0.04	1.80E-07	lb/MMBtu	5.2E-06	2.3E-05	1.18E-08	lb/MMBtu	3.4E-07	1.5E-06
Oth	F-7	32.1	MMBtu/hr	280,851	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.1	13.8	0.0075	lb/MMBtu	0.2	1.1	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.6	11.6	4.90E-07	lb/MMBtu	1.6E-05	6.9E-05	0.01	0.05	1.80E-07	lb/MMBtu	5.8E-06	2.5E-05	1.18E-08	lb/MMBtu	3.8E-07	1.7E-06
ARU																																											
Oth	F-200A	149.8	MMBtu/hr	1,312,684	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.2745	lb/MMBtu	41.1	180.2	0.0200	lb/MMBtu	3.0	13.1	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.6	0.082	lb/MMBtu	12.3	54.1	4.90E-07	lb/MMBtu	7.3E-05	3.2E-04	0.14	0.60	1.80E-07	lb/MMBtu	2.7E-05	1.2E-04	1.18E-08	lb/MMBtu	1.8E-06	7.7E-06
Oth	F-200B	147.0	MMBtu/hr	1,287,827	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.5	0.2745	lb/MMBtu	40.4	176.8	0.0200	lb/MMBtu	2.9	12.9	0.0019	lb/MMBtu	0.3	1.2	0.0040	lb/MMBtu	0.6	2.6	0.082	lb/MMBtu	12.1	53.0	4.90E-07	lb/MMBtu	7.2E-05	3.2E-04	0.13	0.59	1.80E-07	lb/MMBtu	2.6E-05	1.2E-04	1.18E-08	lb/MMBtu	1.7E-06	7.6E-06
BOU																																											
Mod	F-401	7.6	MMBtu/hr	66,485	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.2	0.0980	lb/MMBtu	0.7	3.3	0.0075	lb/MMBtu	0.1	0.2	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.1	0.082	lb/MMBtu	0.6	2.7	4.90E-07	lb/MMBtu	3.7E-06	1.6E-05	0.00	0.01	1.80E-07	lb/MMBtu	1.4E-06	6.0E-06	1.18E-08	lb/MMBtu	8.9E-08	3.9E-07
CFHU																																											
Oth	F-801A	9.2	MMBtu/hr	80,848	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.2	0.0490	lb/MMBtu	0.5	2.0	0.0094	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.8	3.3	4.90E-07	lb/MMBtu	4.5E-06	2.0E-05	0.00	0.02	1.80E-07	lb/MMBtu	1.7E-06	7.3E-06	1.18E-08	lb/MMBtu	1.1E-07	4.8E-07
Oth	F-801B	9.1	MMBtu/hr	79,550	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.2	0.0490	lb/MMBtu	0.4	1.9	0.0094	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.7	3.3	4.90E-07	lb/MMBtu	4.5E-06	1.9E-05	0.00	0.02	1.80E-07	lb/MMBtu	1.6E-06	7.2E-06	1.18E-08	lb/MMBtu	1.1E-07	4.7E-07
Oth	F-801C	0.5	MMBtu/hr	4,160	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.0360	lb/MMBtu	0.0	0.1	0.0094	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0040	lb/MMBtu	0.0	0.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	2.3E-07	1.0E-06	0.00	0.00	1.80E-07	lb/MMBtu	8.5E-08	3.7E-07	1.18E-08	lb/MMBtu	5.6E-09	2.4E-08
CRU																																											
Oth	F-101	23.6	MMBtu/hr	206,634	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0800	lb/MMBtu	1.9	8.3	0.0069	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.1	0.4	0.082	lb/MMBtu	1.9	8.5	4.90E-07	lb/MMBtu	1.2E-05	5.1E-05	0.01	0.03	1.80E-07	lb/MMBtu	4.2E-06	1.9E-05	1.18E-08	lb/MMBtu	2.8E-07	1.2E-06
Oth	F-102	17.0	MMBtu/hr	148,517	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0800	lb/MMBtu	1.4	5.9	0.0069	lb/MMBtu	0.1	0.5	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.4	6.1	4.90E-07	lb/MMBtu	8.3E-06	3.6E-05	0.01	0.02	1.80E-07	lb/MMBtu	3.1E-06	1.3E-05	1.18E-08	lb/MMBtu	2.0E-07	8.7E-07
DDU																																											
Oth	WB-301	33.5	MMBtu/hr	293,608	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0346	lb/MMBtu	1.2	5.1	0.0200	lb/MMBtu	0.7	2.9	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.040	lb/MMBtu	1.3	5.9	4.90E-07	lb/MMBtu	1.6E-05	7.2E-05	0.03	0.13	1.80E-07	lb/MMBtu	6.0E-06	2.6E-05	1.18E-08	lb/MMBtu	3.9E-07	1.7E-06
Oth	WB-302	52.9	MMBtu/hr	463,738	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.3	0.0300	lb/MMBtu	1.6	7.0	0.0200	lb/MMBtu	1.1	4.6	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.9	0.040	lb/MMBtu	2.1	9.3	4.90E-07	lb/MMBtu	2.6E-05	1.1E-04	0.05	0.21	1.80E-07	lb/MMBtu	9.5E-06	4.2E-05	1.18E-08	lb/MMBtu	6.2E-07	2.7E-06
ISOM																																											
Mod	H-1	140.2	MMBtu/hr	1,228,568	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.3	0.2745	lb/MMBtu	38.5	168.6	0.0200	lb/MMBtu	2.8	12.3	0.0019	lb/MMBtu	0.3	1.1	0.0040	lb/MMBtu	0.6	2.5	0.082	lb/MMBtu	11.5	50.6	4.90E-07	lb/MMBtu	6.9E-05	3.0E-04	0.13	0.56	1.80E-07	lb/MMBtu	2.5E-05	1.1E-04	1.18E-08	lb/MMBtu	1.6E-06	7.2E-06
HU																																											
Oth	B-501	145.5	MMBtu/hr	1,274,480	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.4	0.0675	lb/MMBtu	9.8	43.0	0.0650	lb/MMBtu	9.5	41.4	0.0019	lb/MMBtu	0.3	1.2	0.0075	lb/MMBtu	1.1	4.7	0.02	lb/MMBtu	2.9	12.7	4.90E-07	lb/MMBtu	7.1E-05	3.1E-04	0.43	1.90	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.5E-06
Utilities																																											
1SPS																																											
SD	Boiler 3	64.4	MMBtu/hr	563,952	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.5	0.1570	lb/MMBtu	10.1	44.3	0.0200	lb/MMBtu	1.3	5.6	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.5	2.1	0.049	lb/MMBtu	3.2	13.8	4.90E-07	lb/MMBtu	3.2E-05	1.4E-04	0.06	0.26	1.80E-07	lb/MMBtu	1.2E-05	5.1E-05	1.18E-08	lb/MMBtu	7.6E-07	3.3E-06
SD	Boiler 4	44.3	MMBtu/hr	387,967	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.1570	lb/MMBtu	7.0	30.5	0.0200	lb/MMBtu	0.9	3.9	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.3	1.4	0.049	lb/MMBtu	2.2	9.5	4.90E-07	lb/MMBtu	2.2E-05	9.5E-05	0.04	0.18	1.80E-07	lb/MMBtu	8.0E-06	3.5E-05	1.18E-08	lb/MMBtu	5.2E-07	2.3E-06
SD	Boiler 5	99.9	MMBtu/hr	874,982	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.4	0.0930	lb/MMBtu	9.3	40.7	0.0200	lb/MMBtu	2.0	8.7	0.0019	lb/MMBtu	0.2	0.8	0.0075	lb/MMBtu	0.7	3.3	0.248	lb/MMBtu	24.8	108.5	4.90E-07	lb/MMBtu	4.9E-05	2.1E-04	0.09	0.40	1.80E-07	lb/MMBtu	1.8E-05	7.9E-05	1.18E-08	lb/MMBtu	1.2E-06	5.1E-06
SD	Boiler 6	45.0	MMBtu/hr	394,009	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.1	0.0930	lb/MMBtu	4.2	18.3	0.0200	lb/MMBtu	0.9	3.9	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.3	1.5	0.248	lb/MMBtu	11.2	48.9	4.90E-07	lb/MMBtu	2.2E-05	9.7E-05	0.04	0.18	1.80E-07	lb/MMBtu	8.1E-06	3.5E-05	1.18E-08	lb/MMBtu	5.3E-07	2.3E-06
SD	Boiler 7	68.3	MMBtu/hr	598,463	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.6	0.0930	lb/MMBtu	6.4	27.8	0.0200	lb/MMBtu	1.4	6.0	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.5	2.2	0.248	lb/MMBtu	16.9	74.2	4.90E-07	lb/MMBtu	3.3E-05	1.5E-04	0.06	0.27	1.80E-07	lb/MMBtu	1.2E-05	5.4E-05	1.18E-08	lb/MMBtu	8.0E-07	3.5E-06
Lakefront																																											
SD	FBI	17	MMGal/yr	86,369	tons feed	0.0305	lb/unit feed	0.3	1.3	4.7574	lb/Mgal feed	3.7	16.4	0.0093	lb/Mgal feed	0.0	0.0	0.0255	lb/Mgal feed	0.0	0.1	0.

Table C.17. 2004 Combustion Emissions

Process Heaters and Boilers

Code	Process Unit	Usage				VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[2]				CO				Pb				H_2SO_4 Mist		Hg				Be			
						EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
Crude and Coking																																											
11A PS																																											
Oth	H-1X	145.6	MMBtu/hr	1,275,256	MMBtu/yr	0.0054	lb/MMBtu	0.8	3.4	0.1660	lb/MMBtu	24.2	105.8	0.0237	lb/MMBtu	3.4	15.1	0.0019	lb/MMBtu	0.3	1.2	0.0075	lb/MMBtu	1.1	4.8	0.082	lb/MMBtu	12.0	52.5	4.90E-07	lb/MMBtu	7.1E-05	3.1E-04	0.16	0.69	1.80E-07	lb/MMBtu	2.6E-05	1.1E-04	1.18E-08	lb/MMBtu	1.7E-06	7.5E-06
Oth	H-2	18.5	MMBtu/hr	162,191	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0980	lb/MMBtu	1.8	8.0	0.0237	lb/MMBtu	0.4	1.9	0.0019	lb/MMBtu	0.0	0.2	0.0075	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	1.5	6.7	4.90E-07	lb/MMBtu	9.1E-06	4.0E-05	0.02	0.09	1.80E-07	lb/MMBtu	3.3E-06	1.5E-05	1.18E-08	lb/MMBtu	2.2E-07	9.5E-07
Oth	H-3	44.4	MMBtu/hr	389,160	MMBtu/yr	0.0054	lb/MMBtu	0.2	1.0	0.0980	lb/MMBtu	4.4	19.1	0.0237	lb/MMBtu	1.1	4.6	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.3	1.4	0.082	lb/MMBtu	3.7	16.0	4.90E-07	lb/MMBtu	2.2E-05	9.5E-05	0.05	0.21	1.80E-07	lb/MMBtu	8.0E-06	3.5E-05	1.18E-08	lb/MMBtu	5.2E-07	2.3E-06
11C PS																																											
Cont	H-200	107.1	MMBtu/hr	937,919	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.5	0.2745	lb/MMBtu	29.4	128.7	0.0237	lb/MMBtu	2.5	11.1	0.0019	lb/MMBtu	0.2	0.9	0.0075	lb/MMBtu	0.8	3.5	0.082	lb/MMBtu	8.8	38.6	4.90E-07	lb/MMBtu	5.2E-05	2.3E-04	0.12	0.51	1.80E-07	lb/MMBtu	1.9E-05	8.4E-05	1.18E-08	lb/MMBtu	1.3E-06	5.5E-06
Oth	H-300	74.3	MMBtu/hr	651,022	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.1373	lb/MMBtu	10.2	44.7	0.0237	lb/MMBtu	1.8	7.7	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.6	2.4	0.082	lb/MMBtu	6.1	26.8	4.90E-07	lb/MMBtu	3.6E-05	1.6E-04	0.08	0.35	1.80E-07	lb/MMBtu	1.3E-05	5.9E-05	1.18E-08	lb/MMBtu	8.7E-07	3.8E-06
Coker																																											
SD	H-101	34.6	MMBtu/hr	303,049	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.4	14.9	0.0237	lb/MMBtu	0.8	3.6	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.8	12.5	4.90E-07	lb/MMBtu	1.7E-05	7.4E-05	0.04	0.16	1.80E-07	lb/MMBtu	6.2E-06	2.7E-05	1.18E-08	lb/MMBtu	4.1E-07	1.8E-06
SD	H-102	32.1	MMBtu/hr	281,600	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.2	13.8	0.0237	lb/MMBtu	0.8	3.3	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.6	11.6	4.90E-07	lb/MMBtu	1.6E-05	6.9E-05	0.03	0.15	1.80E-07	lb/MMBtu	5.8E-06	2.5E-05	1.18E-08	lb/MMBtu	3.8E-07	1.7E-06
SD	H-103	31.1	MMBtu/hr	272,646	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.7	0.0980	lb/MMBtu	3.1	13.4	0.0237	lb/MMBtu	0.7	3.2	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.6	11.2	4.90E-07	lb/MMBtu	1.5E-05	6.7E-05	0.03	0.15	1.80E-07	lb/MMBtu	5.6E-06	2.5E-05	1.18E-08	lb/MMBtu	3.7E-07	1.6E-06
SD	H-104	33.3	MMBtu/hr	291,574	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.3	14.3	0.0237	lb/MMBtu	0.8	3.5	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.7	12.0	4.90E-07	lb/MMBtu	1.6E-05	7.1E-05	0.04	0.16	1.80E-07	lb/MMBtu	6.0E-06	2.6E-05	1.18E-08	lb/MMBtu	3.9E-07	1.7E-06
12PS																																											
SD	H-1AN	83.6	MMBtu/hr	732,363	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.0	0.2745	lb/MMBtu	22.9	100.5	0.0237	lb/MMBtu	2.0	8.7	0.0019	lb/MMBtu	0.2	0.7	0.0075	lb/MMBtu	0.6	2.7	0.082	lb/MMBtu	6.9	30.2	4.90E-07	lb/MMBtu	4.1E-05	1.8E-04	0.09	0.40	1.80E-07	lb/MMBtu	1.5E-05	6.6E-05	1.18E-08	lb/MMBtu	9.8E-07	4.3E-06
SD	H-1AS	58.6	MMBtu/hr	513,370	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.4	0.2745	lb/MMBtu	16.1	70.5	0.0237	lb/MMBtu	1.4	6.1	0.0019	lb/MMBtu	0.1	0.5	0.0075	lb/MMBtu	0.4	1.9	0.082	lb/MMBtu	4.8	21.1	4.90E-07	lb/MMBtu	2.9E-05	1.3E-04	0.06	0.28	1.80E-07	lb/MMBtu	1.1E-05	4.6E-05	1.18E-08	lb/MMBtu	6.9E-07	3.0E-06
SD	H-1B	166.5	MMBtu/hr	1,458,600	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.9	0.2745	lb/MMBtu	45.7	200.2	0.0237	lb/MMBtu	3.9	17.3	0.0019	lb/MMBtu	0.3	1.4	0.0075	lb/MMBtu	1.2	5.4	0.082	lb/MMBtu	13.7	60.1	4.90E-07	lb/MMBtu	8.2E-05	3.6E-04	0.18	0.79	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.18E-08	lb/MMBtu	2.0E-06	8.6E-06
SD	H-2	120.4	MMBtu/hr	1,054,784	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.8	0.0360	lb/MMBtu	4.3	19.0	0.0237	lb/MMBtu	2.8	12.5	0.0019	lb/MMBtu	0.2	1.0	0.0075	lb/MMBtu	0.9	3.9	0.0001	lb/MMBtu	0.0	0.1	4.90E-07	lb/MMBtu	5.9E-05	2.6E-04	0.13	0.57	1.80E-07	lb/MMBtu	2.2E-05	9.5E-05	1.18E-08	lb/MMBtu	1.4E-06	6.2E-06
SD	H-1CN	67.2	MMBtu/hr	588,736	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.6	0.0980	lb/MMBtu	6.6	28.9	0.0237	lb/MMBtu	1.6	7.0	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.3	1.2	0.082	lb/MMBtu	5.5	24.2	4.90E-07	lb/MMBtu	3.3E-05	1.4E-04	0.07	0.32	1.80E-07	lb/MMBtu	1.2E-05	5.3E-05	1.18E-08	lb/MMBtu	7.9E-07	3.5E-06
SD	H-1CX	205.0	MMBtu/hr	1,795,720	MMBtu/yr	0.0054	lb/MMBtu	1.1	4.8	0.0990	lb/MMBtu	20.3	88.9	0.0237	lb/MMBtu	4.9	21.2	0.0019	lb/MMBtu	0.4	1.7	0.0040	lb/MMBtu	0.8	3.6	0.082	lb/MMBtu	16.9	73.9	4.90E-07	lb/MMBtu	1.0E-04	4.4E-04	0.22	0.98	1.80E-07	lb/MMBtu	3.7E-05	1.6E-04	1.18E-08	lb/MMBtu	2.4E-06	1.1E-05
Hydroprocessing																																											
3UF																																											
SD	H-1	87.3	MMBtu/hr	764,513	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.1	0.2745	lb/MMBtu	24.0	104.9	0.0061	lb/MMBtu	0.5	2.3	0.0019	lb/MMBtu	0.2	0.7	0.0040	lb/MMBtu	0.3	1.5	0.082	lb/MMBtu	7.2	31.5	4.90E-07	lb/MMBtu	4.3E-05	1.9E-04	0.02	0.11	1.80E-07	lb/MMBtu	1.6E-05	6.9E-05	1.18E-08	lb/MMBtu	1.0E-06	4.5E-06
SD	H-2	110.5	MMBtu/hr	968,099	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.6	0.2745	lb/MMBtu	30.3	132.9	0.0061	lb/MMBtu	0.7	3.0	0.0019	lb/MMBtu	0.2	0.9	0.0040	lb/MMBtu	0.4	1.9	0.082	lb/MMBtu	9.1	39.9	4.90E-07	lb/MMBtu	5.4E-05	2.4E-04	0.03	0.14	1.80E-07	lb/MMBtu	2.0E-05	8.7E-05	1.18E-08	lb/MMBtu	1.3E-06	5.7E-06
SD	F-7	14.2	MMBtu/hr	124,422	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0980	lb/MMBtu	1.4	6.1	0.0061	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.2	0.082	lb/MMBtu	1.2	5.1	4.90E-07	lb/MMBtu	7.0E-06	3.0E-05	0.00	0.02	1.80E-07	lb/MMBtu	2.6E-06	1.1E-05	1.18E-08	lb/MMBtu	1.7E-07	7.3E-07
4UF																																											
Oth	F-1	37.8	MMBtu/hr	331,540	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0980	lb/MMBtu	3.7	16.3	0.0059	lb/MMBtu	0.2	1.0	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.082	lb/MMBtu	3.1	13.7	4.90E-07	lb/MMBtu	1.9E-05	8.1E-05	0.01	0.05	1.80E-07	lb/MMBtu	6.8E-06	3.0E-05	1.18E-08	lb/MMBtu	4.5E-07	2.0E-06
Oth	F-8A	67.2	MMBtu/hr	588,482	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.6	0.2745	lb/MMBtu	18.4	80.8	0.0059	lb/MMBtu	0.4	1.7	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.3	1.2	0.082	lb/MMBtu	5.5	24.2	4.90E-07	lb/MMBtu	3.3E-05	1.4E-04	0.02	0.08	1.80E-07	lb/MMBtu	1.2E-05	5.3E-05	1.18E-08	lb/MMBtu	7.9E-07	3.5E-06
Oth	F-8B	63.5	MMBtu/hr	556,179	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.5	0.2745	lb/MMBtu	17.4	76.3	0.0059	lb/MMBtu	0.4	1.7	0.0019	lb/MMBtu	0.1	0.5	0.0040	lb/MMBtu	0.3	1.1	0.082	lb/MMBtu	5.2	22.9	4.90E-07	lb/MMBtu	3.1E-05	1.4E-04	0.02	0.08	1.80E-07	lb/MMBtu	1.1E-05	5.0E-05	1.18E-08	lb/MMBtu	7.5E-07	3.3E-06
Oth	F-2	190.7	MMBtu/hr	1,670,948	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.5	0.1863	lb/MMBtu	35.5	155.6	0.0059	lb/MMBtu	1.1	5.0	0.0019	lb/MMBtu	0.4	1.6	0.0040	lb/MMBtu	0.8	3.3	0.082	lb/MMBtu	15.7	68.8	4.90E-07	lb/MMBtu	9.4E-05	4.1E-04	0.05	0.23	1.80E-07	lb/MMBtu	3.4E-05	1.5E-04	1.18E-08	lb/MMBtu	2.2E-06	9.8E-06
Oth	F-3	165.3	MMBtu/hr	1,448,451	MMBtu/yr	0.0054	lb/MMBtu	0.9	3.9	0.2745	lb/MMBtu	45.4	198.8	0.0059	lb/MMBtu	1.0	4.3	0.0019	lb/MMBtu	0.3	1.3	0.0040	lb/MMBtu	0.7	2.9	0.082	lb/MMBtu	13.6	59.6	4.90E-07	lb/MMBtu	8.1E-05	3.6E-04	0.05	0.20	1.80E-07	lb/MMBtu	3.0E-05	1.3E-04	1.18E-08	lb/MMBtu	1.9E-06	8.5E-06
Oth	F-4	94.2	MMBtu/hr	825,437	MMBtu/yr	0.0054	lb/MMBtu	0.5	2.2	0.2745	lb/MMBtu	25.9	113.3	0.0059	lb/MMBtu	0.6	2.4	0.0019	lb/MMBtu	0.2	0.8	0.0040	lb/MMBtu	0.4	1.7	0.082	lb/MMBtu	7.8	34.0	4.90E-07	lb/MMBtu	4.6E-05	2.0E-04	0.03	0.11	1.80E-07	lb/MMBtu	1.7E-05	7.4E-05	1.18E-08	lb/MMBtu	1.1E-06	4.9E-06
Oth	F-5	47.7	MMBtu/hr	417,621	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0980	lb/MMBtu	4.7	20.5	0.0059	lb/MMBtu	0.3	1.2	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.082	lb/MMBtu	3.9	17.2	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.01	0.06	1.80E-07	lb/MMBtu	8.6E-06	3.8E-05	1.18E-08	lb/MMBtu	5.6E-07	2.5E-06
Oth	F-6	35.8	MMBtu/hr	313,608	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.5	15.4	0.0059	lb/MMBtu	0.2	0.9	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.9	12.9	4.90E-07	lb/MMBtu	1.8E-05	7.7E-05	0.01	0.04	1.80E-07	lb/MMBtu	6.4E-06	2.8E-05	1.18E-08	lb/MMBtu	4.2E-07	1.8E-06
Oth	F-7	32.4	MMBtu/hr	284,134	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.8	0.0980	lb/MMBtu	3.2	13.9	0.0059	lb/MMBtu	0.2	0.8	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.1	0.6	0.082	lb/MMBtu	2.7	11.7	4.90E-07	lb/MMBtu	1.6E-05	7.0E-05	0.01	0.04	1.80E-07	lb/MMBtu	5.8E-06	2.6E-05	1.18E-08	lb/MMBtu	3.8E-07	1.7E-06
ARU																																											
Oth	F-200A	191.3	MMBtu/hr	1,675,689	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.5	0.2745	lb/MMBtu	52.5	230.0	0.0237	lb/MMBtu	4.5	19.8	0.0019	lb/MMBtu	0.4	1.6	0.0040	lb/MMBtu	0.8	3.4	0.082	lb/MMBtu	15.8	69.0	4.90E-07	lb/MMBtu	9.4E-05	4.1E-04	0.21	0.91	1.80E-07	lb/MMBtu	3.4E-05	1.5E-04	1.18E-08	lb/MMBtu	2.3E-06	9.9E-06
Oth	F-200B	179.7	MMBtu/hr	1,574,497	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.2	0.2745	lb/MMBtu	49.3	216.1	0.0237	lb/MMBtu	4.3	18.6	0.0019	lb/MMBtu	0.3	1.5	0.0040	lb/MMBtu	0.7	3.1	0.082	lb/MMBtu	14.8	64.8	4.90E-07	lb/MMBtu	8.8E-05	3.9E-04	0.20	0.86	1.80E-07	lb/MMBtu	3.2E-05	1.4E-04	1.18E-08	lb/MMBtu	2.1E-06	9.3E-06
BOU																																											
Mod	F-401	15.0	MMBtu/hr	131,318	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0980	lb/MMBtu	1.5	6.4	0.0059	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.2	5.4	4.90E-07	lb/MMBtu	7.3E-06	3.2E-05	0.00	0.02	1.80E-07	lb/MMBtu	2.7E-06	1.2E-05	1.18E-08	lb/MMBtu	1.8E-07	7.7E-07
CFHU																																											
Oth	F-801A	10.8	MMBtu/hr	94,183	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0490	lb/MMBtu	0.5	2.3	0.0078	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.9	3.9	4.90E-07	lb/MMBtu	5.3E-06	2.3E-05	0.00	0.02	1.80E-07	lb/MMBtu	1.9E-06	8.5E-06	1.18E-08	lb/MMBtu	1.3E-07	5.5E-07
Oth	F-801B	11.3	MMBtu/hr	98,575	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.3	0.0490	lb/MMBtu	0.6	2.4	0.0078	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.0	0.2	0.082	lb/MMBtu	0.9	4.1	4.90E-07	lb/MMBtu	5.5E-06	2.4E-05	0.00	0.02	1.80E-07	lb/MMBtu	2.0E-06	8.9E-06	1.18E-08	lb/MMBtu	1.3E-07	5.8E-07
Oth	F-801C	0.1	MMBtu/hr	1,131	MMBtu/yr	0.0054	lb/MMBtu	0.0	0.0	0.0360	lb/MMBtu	0.0	0.0	0.0078	lb/MMBtu	0.0	0.0	0.0019	lb/MMBtu	0.0	0.0	0.0040	lb/MMBtu	0.0	0.0	0.0001	lb/MMBtu	0.0	0.0	4.90E-07	lb/MMBtu	6.3E-08	2.8E-07	0.00	0.00	1.80E-07	lb/MMBtu	2.3E-08	1.0E-07	1.18E-08	lb/MMBtu	1.5E-09	6.7E-09
CRU																																											
Oth	F-101	18.4	MMBtu/hr	160,857	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.4	0.0800	lb/MMBtu	1.5	6.4	0.0061	lb/MMBtu	0.1	0.5	0.0019	lb/MMBtu	0.0	0.1	0.0040	lb/MMBtu	0.1	0.3	0.082	lb/MMBtu	1.5	6.6	4.90E-07	lb/MMBtu	9.0E-06	3.9E-05	0.01	0.02	1.80E-07	lb/MMBtu	3.3E-06	1.4E-05	1.18E-08	lb/MMBtu	2.2E-07	9.5E-07
Oth	F-102	26.1	MMBtu/hr	228,260	MMBtu/yr	0.0054	lb/MMBtu	0.1	0.6	0.0800	lb/MMBtu	2.1	9.1	0.0061	lb/MMBtu	0.2	0.7	0.0019	lb/MMBtu	0.0	0.2	0.0040	lb/MMBtu	0.1	0.5	0.082	lb/MMBtu	2.1	9.4	4.90E-07	lb/MMBtu	1.3E-05	5.6E-05	0.01	0.03	1.80E-07	lb/MMBtu	4.7E-06	2.1E-05	1.18E-08	lb/MMBtu	3.1E-07	1.3E-06
DDU																																											
Oth	WB-301	39.3	MMBtu/hr	344,060	MMBtu/yr	0.0054	lb/MMBtu	0.2	0.9	0.0346	lb/MMBtu	1.4	6.0	0.0237	lb/MMBtu	0.9	4.1	0.0019	lb/MMBtu	0.1	0.3	0.0040	lb/MMBtu	0.2	0.7	0.040	lb/MMBtu	1.6	6.9	4.90E-07	lb/MMBtu	1.9E-05	8.4E-05	0.04	0.19	1.80E-07	lb/MMBtu	7.1E-06	3.1E-05	1.18E-08	lb/MMBtu	4.6E-07	2.0E-06
Oth	WB-302	47.4	MMBtu/hr	415,593	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.1	0.0300	lb/MMBtu	1.4	6.2	0.0237	lb/MMBtu	1.1	4.9	0.0019	lb/MMBtu	0.1	0.4	0.0040	lb/MMBtu	0.2	0.8	0.040	lb/MMBtu	1.9	8.3	4.90E-07	lb/MMBtu	2.3E-05	1.0E-04	0.05	0.23	1.80E-07	lb/MMBtu	8.5E-06	3.7E-05	1.18E-08	lb/MMBtu	5.6E-07	2.4E-06
ISOM																																											
Mod	H-1	130.2	MMBtu/hr	1,140,305	MMBtu/yr	0.0054	lb/MMBtu	0.7	3.1	0.2745	lb/MMBtu	35.7	156.5	0.0237	lb/MMBtu	3.1	13.5	0.0019	lb/MMBtu	0.2	1.1	0.0040	lb/MMBtu	0.5	2.3	0.082	lb/MMBtu	10.7	47.0	4.90E-07	lb/MMBtu	6.4E-05	2.8E-04	0.14	0.62	1.80E-07	lb/MMBtu	2.3E-05	1.0E-04	1.18E-08	lb/MMBtu	1.5E-06	6.7E-06
HU																																											
Oth	B-501	192.2	MMBtu/hr	1,683,372	MMBtu/yr	0.0054	lb/MMBtu	1.0	4.5	0.0675	lb/MMBtu	13.0	56.8	0.0771	lb/MMBtu	14.8	64.9	0.0019	lb/MMBtu	0.4	1.6	0.0075	lb/MMBtu	1.4	6.3	0.02	lb/MMBtu	3.8	16.8	4.90E-07	lb/MMBtu	9.4E-05	4.1E-04	0.68	2.98	1.80E-07	lb/MMBtu	3.5E-05	1.5E-04	1.18E-08	lb/MMBtu	2.3E-06	9.9E-06
Utilities																																											
1SPS																																											
SD	Boiler 3	52.9	MMBtu/hr	463,525	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.1570	lb/MMBtu	8.3	36.4	0.0237	lb/MMBtu	1.3	5.5	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.4	1.7	0.049	lb/MMBtu	2.6	11.4	4.90E-07	lb/MMBtu	2.6E-05	1.1E-04	0.06	0.25	1.80E-07	lb/MMBtu	9.5E-06	4.2E-05	1.18E-08	lb/MMBtu	6.2E-07	2.7E-06
SD	Boiler 4	75.4	MMBtu/hr	660,481	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.8	0.1570	lb/MMBtu	11.8	51.8	0.0237	lb/MMBtu	1.8	7.8	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.6	2.5	0.049	lb/MMBtu	3.7	16.2	4.90E-07	lb/MMBtu	3.7E-05	1.6E-04	0.08	0.36	1.80E-07	lb/MMBtu	1.4E-05	5.9E-05	1.18E-08	lb/MMBtu	8.9E-07	3.9E-06
SD	Boiler 5	69.9	MMBtu/hr	612,637	MMBtu/yr	0.0054	lb/MMBtu	0.4	1.7	0.0930	lb/MMBtu	6.5	28.5	0.0237	lb/MMBtu	1.7	7.2	0.0019	lb/MMBtu	0.1	0.6	0.0075	lb/MMBtu	0.5	2.3	0.248	lb/MMBtu	17.3	76.0	4.90E-07	lb/MMBtu	3.4E-05	1.5E-04	0.08	0.33	1.80E-07	lb/MMBtu	1.3E-05	5.5E-05	1.18E-08	lb/MMBtu	8.2E-07	3.6E-06
SD	Boiler 6	49.0	MMBtu/hr	429,528	MMBtu/yr	0.0054	lb/MMBtu	0.3	1.2	0.0930	lb/MMBtu	4.6	20.0	0.0237	lb/MMBtu	1.2	5.1	0.0019	lb/MMBtu	0.1	0.4	0.0075	lb/MMBtu	0.4	1.6	0.248	lb/MMBtu	12.2	53.3	4.90E-07	lb/MMBtu	2.4E-05	1.1E-04	0.05	0.23	1.80E-07	lb/MMBtu	8.8E-06	3.9E-05	1.18E-08	lb/MMBtu	5.8E-07	2.5E-06
SD	Boiler 7	114.4	MMBtu/hr	1,002,405	MMBtu/yr	0.0054	lb/MMBtu	0.6	2.7	0.0930	lb/MMBtu	10.6	46.6	0.0237	lb/MMBtu	2.7	11.9	0.0019	lb/MMBtu	0.2	0.9	0.0075	lb/MMBtu	0.9	3.7	0.248	lb/MMBtu	28.4	124.3	4.90E-07	lb/MMBtu	5.6E-05	2.5E-04	0.12	0.54	1.80E-07	lb/MMBtu	2.1E-05	9.0E-05	1.18E-08	lb/MMBtu	1.3E-06	5.9E-06
Lakefront																																											
SD	FBI	18	MMGal/yr	89,905	tons feed	0.0305	lb/unit feed	0.3	1.4	4.7574	lb/Mgal feed	3.9	17.1	0.0093	lb/Mgal feed	0.0	0.0	0.0255	lb/Mgal feed	0.0	0.1

Table C.18. Baseline FBI Beryllium Emissions

Year	Feed		Be Emission Factor		Be Emissions (lb)
2002	17.26	MMGal/yr	8.22E-06	lb/Mgal	0.14
2003	17.26	MMGal/yr	5.73E-06	lb/Mgal	0.10
2004	17.97	MMGal/yr	8.22E-06	lb/Mgal	0.15
2005	12.93	MMGal/yr	8.22E-06	lb/Mgal	0.11
2006	7.63	MMGal/yr	8.22E-06	lb/Mgal	0.06

Baseline Average	Be Emissions (tpy)
2002-2003	6.02E-05
2003-2004	6.16E-05
2004-2005	6.35E-05
2005-2006	4.22E-05

Table C.19. Project Sulfur Recovery Complex Emissions

Process Unit	Natural Gas Usage (MMBtu/hr)	VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
COT 1 and 2	144	0.0054	lb/MMBtu	0.8	3.4	0.08	lb/MMBtu	11.5	50.5	0.0006	lb/MMBtu	0.1	0.4	0.0019	lb/MMBtu	0.3	1.2	0.0075	lb/MMBtu	1.1	4.7	4.90E-07	lb/MMBtu	7.06E-05	3.09E-04	0.004	0.02	1.80E-07	lb/MMBtu	2.59E-05	1.14E-04	1.18E-08	lb/MMBtu	1.69E-06	7.42E-06

Process Unit	Future SO_2 Conc. (PPM)	Exhaust Air Flow (scfh)	SO_2		H_2SO_4 Mist	
			lb/hr[1]	tpy	lb/hr[1]	tpy
COT 1 and 2	45	5,929,500	44.4	194.5	2.0	8.9

Process Unit	Future H_2S (lb-mol/hr)	Anticipated days/yr at operating rate	H_2S		Total Reduced Sulfur[3]	
			lb/hr[1]	tpy	lb/hr[1]	tpy
COT 1 and 2	0.06	365	2.0	8.9	2.0	8.9

Process Unit	CO Combustion Emissions				CO Process Emissions[2]	
	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy
COT 1 and 2	0.05	lb/MMBtu	7.2	31.5	5.4	23.5

Sulfur Loading Emissions**

	H_2S Conc.	H_2S Emitted		Total Reduced Sulfur[3]	
	ppm	lb/hr	tpy	lb/hr	tpy
Before Loading	10	1.2	5.3	1.2	5.3
After Loading	0	0.0	0.0	0.0	0.0
H_2S Emitted		1.2	5.3	1.2	5.3

[1] Hourly emission rate represents annual average hourly emissions.
[2] Total CO emissions from the COT 1 and 2 are estimated to be 55 ton/yr. Combustion emissions are calculated using vendor emission factors (See Table 1) and are based on the amount of natural gas combusted at the units. An additional amount of CO emissions is estimated based on CO2 inherent in the process gas fed to the SRU which may be emitted as additional CO emissions at the COTs.
[3] Emissions of Total Reduced Sulfur from the COTs and sulfur loading are assumed to be equal to emissions of H_2S.

* Each COT is capable of operating to accommodate the total SRU train loading of 1300 LTPD for the purpose of redundancy.
** Based on future capacity of 1300 LTPD sulfur production. Conservatively assumes that all H_2S present in sulfur is emitted during the loading process.
*** In the future, sulfur pits will be controlled and routed back to the SRU process, therefore there will be no H_2S emissions from the sulfur pits.

Table C.20. 1999 Sulfur Recovery Complex Emissions

Combustor Emissions

Process Unit	Natural Gas Usage (MMscf/yr)	VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				CO				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
SBS TGU	0.0	5.5	lb/MMscf	0.0	0.0	100	lb/MMscf	0.0	0.0	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.0	84	lb/MMscf	0.0	0.0	5.00E-04	lb/MMscf	0.0E+00	0.0E+00	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
Beavon-Stretford TGU	47.2	5.5	lb/MMscf	0.0	0.1	100	lb/MMscf	0.5	2.4	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.2	84	lb/MMscf	0.5	2.0	5.00E-04	lb/MMscf	2.7E-06	1.2E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
SRU Incinerator	108.6	5.5	lb/MMscf	0.1	0.3	100	lb/MMscf	1.2	5.4	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.4	84	lb/MMscf	1.0	4.6	5.00E-04	lb/MMscf	6.2E-06	2.7E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000

* The total flow to the Beavon-Stretford TGU in 1999 was 309,785.9 ton/yr based on data recorded by the BP Whiting PI data collection system.

Note the PM_{10} emission limit provided in the PM_{10} SIP is 0.110 lb/ton. Therefore, in 1999 the PM_{10} emissions were below this limit (359.0 lb PM_{10}/yr)/(309,785.9 ton/yr) = 0.0012 lb/ton.

SBS Process Emissions

Process Unit	Sulfur Flow (LTPD)	SBS Exhaust	CEMS Data SO_2 Conc.	SO_2[1] (lb/hr)	SO_2 (tpy)	H_2SO_4 Mist	
						lb/hr[1]	tpy
SBS TGU	0.0	0.0	0	0.0	0.0	0.00	0.00

Beavon Stretford Process Emissions

No. of Days Combusting	Actual Airflow MAscf/hr	SO_2[1] lb/hr**	SO_2 tpy	H_2SO_4 Mist		H_2S lb/hr	H_2S tpy	Total Reduced Sulfur lb/hr	Total Reduced Sulfur tpy
				lb/hr[1]	tpy				
81	1,866	7.7	7.5	0.36	0.35	0.6	2.6	12.6	55.4

** The SO_2 concentration is calculated based on average daily H_2S and TRS CEMS Data.

The Beavon Stretford combustor temperature ramps up if the H_2S concentration approaches 10 ppm. BP Whiting has estimated that approximately 30% of the TRS/H2S sulfur is converted to SO_2 after the combustion temperature ramps up.

[1] Hourly emission rate represents annual average hourly emissions.

**** Sulfur pit loading emissions have only been included for the H_2S/TRS baseline years of 2000-2001.

Table C.21. 2000 Sulfur Recovery Complex Emissions

Combustor Emissions

Process Unit	Natural Gas Usage (MMscf/yr)	VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				CO				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
SBS TGU	0.0	5.5	lb/MMscf	0.0	0.0	100	lb/MMscf	0.0	0.0	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.0	84	lb/MMscf	0.0	0.0	5.00E-04	lb/MMscf	0.0E+00	0.0E+00	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
Beavon-Stretford TGU	90.1	5.5	lb/MMscf	0.1	0.2	100	lb/MMscf	1.0	4.5	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.3	84	lb/MMscf	0.9	3.8	5.00E-04	lb/MMscf	5.1E-06	2.3E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
SRU Incinerator	114.0	5.5	lb/MMscf	0.1	0.3	100	lb/MMscf	1.3	5.7	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.4	84	lb/MMscf	1.1	4.8	5.00E-04	lb/MMscf	6.5E-06	2.9E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000

* The total flow to the Beavon-Stretford TGU in 2000 was 317,615.7 ton/yr based on data recorded by the BP Whiting PI data collection system.
Note the PM_{10} emission limit provided in the PM_{10} SIP is 0.110 lb/ton. Therefore, in 2000 the PM_{10} emissions were below this limit (684.6 lb PM_{10}/yr)/(317,615.7 ton/yr) = 0.002 lb/ton.

SBS Process Emissions

Process Unit	Sulfur Flow (LTPD)	SBS Exhaust	CEMS Data SO_2 Conc.	SO_2[1] (lb/hr)	SO_2 (tpy)	H_2SO_4 Mist	
						lb/hr[1]	tpy
SBS TGU	0.0	0.0	0	0.0	0.0	0.00	0.00

Beavon Stretford Process Emissions

No. of Days Combusting	Actual Airflow MAscf/hr	SO_2[1] lb/hr**	SO_2 tpy	H_2SO_4 Mist		H_2S lb/hr	H_2S tpy	Total Reduced Sulfur lb/hr	Total Reduced Sulfur tpy
				lb/hr[1]	tpy				
47	1,774	6.5	3.7	0.30	0.17	0.5	2.2	13.2	57.7

** The SO_2 concentration is calculated based on average daily H_2S and TRS CEMS Data.

The Beavon Stretford combustor temperature ramps up if the H_2S concentration approaches 10 ppm. BP Whiting has estimated that approximately 30%

of the TRS/H2S sulfur is converted to SO_2 after the combustion temperature ramps up.

Sulfur Pit Emissions

Tank No.	Saturated Sulfur Conc. (ppm)	Average Sulfur Stored (LTPD)	Tank Capacity (LT)	Average Residence Time (days)	H_2S Emissions (lb/hr)	H_2S Emissions (ton/yr)	
TK-201	250	144.1	63.8	0.22	0.2	1.0	
TK-231	250	94.7	63.8	0.34	0.2	1.0	
TK-261	250	175.3	58.0	0.33	0.4	1.8	
TK-310	204.0	414.1	2400.0	4.35	3.7	16.4	

Sulfur Loading Emissions***

	H_2S Conc. (ppm)	Average Sulfur Stored (LTPD)	H_2S in sulfur (lb/hr)	H_2S in sulfur (ton/yr)	H_2S Emitted (lb/hr)	H_2S Emitted (ton/yr)	
Before Loading	250	414.1	9.7	42.5			
After Loading	200	414.1	7.8	34.0			
					1.9	8.5	

*** The difference in the amount of H_2S in the sulfur before and after loading is assumed to be emitted to atmosphere as part of the loading process.

[1] Hourly emission rate represents annual average hourly emissions.

**** Sulfur pit loading emissions have only been included for the H_2S/TRS baseline years of 2000-2001.

Table C.22. 2001 Sulfur Recovery Complex Emissions

Combustor Emissions

Process Unit	Natural Gas Usage (MMscf/yr)	VOC				NO_x				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				CO				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
SBS TGU	0.0	5.5	lb/MMscf	0.0	0.0	100	lb/MMscf	0.0	0.0	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.0	84	lb/MMscf	0.0	0.0	5.00E-04	lb/MMscf	0.0E+00	0.0E+00	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
Beavon-Stretford TGU	83.1	5.5	lb/MMscf	0.1	0.2	100	lb/MMscf	0.9	4.2	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.3	84	lb/MMscf	0.8	3.5	5.00E-04	lb/MMscf	4.7E-06	2.1E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
SRU Incinerator	123.3	5.5	lb/MMscf	0.1	0.3	100	lb/MMscf	1.4	6.2	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.5	84	lb/MMscf	1.2	5.2	5.00E-04	lb/MMscf	7.0E-06	3.1E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000

* The total flow to the Beavon-Stretford TGU in 2001 was 321,415.6 ton/yr based on data recorded by the BP Whiting PI data collection system.
Note the PM_{10} emission limit provided in the PM_{10} SIP is 0.110 lb/ton. Therefore, in 2001 the PM_{10} emissions were below this limit (631.9 lb PM_{10}/yr)/(321,415.6 ton/yr) = 0.0002 lb/ton.

SBS Process Emissions

Process Unit	Sulfur Flow (LTPD)	SBS Exhaust	CEMS Data SO_2 Conc.	SO_2[1] (lb/hr)	SO_2 (tpy)	H_2SO_4 Mist	
						lb/hr[1]	tpy
SBS TGU	0.0	0.0	0	0.0	0.0	0.00	0.00

Beavon Stretford Process Emissions

No. of Days Combusting	Actual Airflow MAscf/hr	SO_2[1] lb/hr**	SO_2 tpy	H_2SO_4 Mist		H_2S lb/hr	H_2S tpy	Total Reduced Sulfur lb/hr	Total Reduced Sulfur tpy
				lb/hr[1]	tpy				
74	1,885	7.1	6.3	0.33	0.29	0.5	2.3	15.3	67.2

** The SO_2 concentration is calculated based on average daily H_2S and TRS CEMS Data.

The Beavon Stretford combustor temperature ramps up if the H_2S concentration approaches 10 ppm. BP Whiting has estimated that approximately 30% of the TRS/H2S sulfur is converted to SO_2 after the combustion temperature ramps up.

Sulfur Pit Emissions

Tank No.	Saturated Sulfur Conc. (ppm)	Average Sulfur Stored (LTPD)	Tank Capacity (LT)	Average Residence Time (days)	H_2S Emissions (lb/hr)	H_2S Emissions (ton/yr)	
TK-201	250	120.3	63.8	0.27	0.2	1.0	
TK-231	250	123.3	63.8	0.26	0.2	1.0	
TK-261	250	159.2	58.0	0.36	0.4	1.8	
TK-310	202.9	402.8	2400.0	4.47	3.6	15.9	

Sulfur Loading Emissions***

	H_2S Conc. (ppm)	Average Sulfur Stored (LTPD)	H_2S in sulfur (lb/hr)	H_2S in sulfur (ton/yr)	H_2S Emitted (lb/hr)	H_2S Emitted (ton/yr)	
Before Loading	250	402.8	9.4	41.4			
After Loading	200	402.8	7.6	33.1			
					1.9	8.3	

*** The difference in the amount of H_2S in the sulfur before and after loading is assumed to be emitted to atmosphere as part of the loading process.
[1] Hourly emission rate represents annual average hourly emissions.
**** Sulfur pit loading emissions have only been included for the H_2S/TRS baseline years of 2000-2001.

Table C.23. 2002 Sulfur Recovery Complex Emissions

Combustor Emissions

Process Unit	Natural Gas Usage (MMscf/yr)	VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				CO				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
SBS TGU	78.9	5.5	lb/MMscf	0.0	0.2	100	lb/MMscf	0.9	3.9	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.3	84	lb/MMscf	0.8	3.3	5.00E-04	lb/MMscf	4.5E-06	2.0E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
Beavon-Stretford TGU	48.4	5.5	lb/MMscf	0.0	0.1	100	lb/MMscf	0.6	2.4	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.2	84	lb/MMscf	0.5	2.0	5.00E-04	lb/MMscf	2.8E-06	1.2E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
SRU Incinerator	89.7	5.5	lb/MMscf	0.1	0.2	100	lb/MMscf	1.0	4.5	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.3	84	lb/MMscf	0.9	3.8	5.00E-04	lb/MMscf	5.1E-06	2.2E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000

* The total flow to the Beavon-Stretford TGU in 2002 was 281,855.0 ton/yr based on data recorded by the BP Whiting PI data collection system.
Note the PM_{10} emission limit provided in the PM_{10} SIP is 0.110 lb/ton. Therefore, in 2002 the PM_{10} emissions were below this limit (368.17 lb PM_{10}/yr)/(281,855.0 ton/yr) = 0.0013 lb/ton.

SBS Process Emissions

Process Unit	Sulfur Flow (LTPD)	SBS Exhaust	CEMS Data SO_2 Conc.	SO_2[1] (lb/hr)	SO_2 (tpy)	H_2SO_4 Mist	
						lb/hr[1]	tpy
SBS TGU	0.008	90.0	3	0.0	0.2	0.00	0.01

Beavon Stretford Process Emissions

No. of Days Combusting	Actual Airflow MAscf/hr	SO_2[1] lb/hr**	SO_2 tpy	H_2SO_4 Mist		H_2S lb/hr	H_2S tpy	Total Reduced Sulfur lb/hr	Total Reduced Sulfur tpy
				lb/hr[1]	tpy				
108	1,603	5.7	7.4	0.26	0.34	0.7	3.1	11.8	51.6

** The SO_2 concentration is calculated based on average daily H_2S and TRS CEMS Data.

The Beavon Stretford combustor temperature ramps up if the H_2S concentration approaches 10 ppm. BP Whiting has estimated that approximately 30% of the TRS/H2S sulfur is converted to SO_2 after the combustion temperature ramps up.

Sulfur Loading Emissions***

	H_2S Conc. (ppm)	Average Sulfur Stored (LTPD)	H_2S in sulfur (lb/hr)	H_2S in sulfur (ton/yr)	H_2S Emitted (lb/hr)	H_2S Emitted (ton/yr)	
Before Loading	250	344.9	8.1	35.4			
After Loading	200	344.9	6.5	28.3			
					1.6	7.1	

*** The difference in the amount of H_2S in the sulfur before and after loading is assumed to be emitted to atmosphere as part of the loading process.
[1] Hourly emission rate represents annual average hourly emissions.
**** Sulfur pit loading emissions have only been included for the H_2S/TRS baseline years of 2000-2001.

Table C.24. 2003 Sulfur Recovery Complex Emissions

Combustor Emissions

Process Unit	Natural Gas Usage (MMscf/yr)	VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				CO				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
SBS TGU	58.8	5.5	lb/MMscf	0.0	0.2	100	lb/MMscf	0.7	2.9	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.2	84	lb/MMscf	0.6	2.5	5.00E-04	lb/MMscf	3.4E-06	1.5E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
Beavon-Stretford TGU	47.3	5.5	lb/MMscf	0.0	0.1	100	lb/MMscf	0.5	2.4	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.2	84	lb/MMscf	0.5	2.0	5.00E-04	lb/MMscf	2.7E-06	1.2E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
SRU Incinerator	77.2	5.5	lb/MMscf	0.0	0.2	100	lb/MMscf	0.9	3.9	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.3	84	lb/MMscf	0.7	3.2	5.00E-04	lb/MMscf	4.4E-06	1.9E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000

* The total flow to the Beavon-Stretford TGU in 2003 was 261,933.7 ton/yr based on data recorded by the BP Whiting PI data collection system.
Note the PM_{10} emission limit provided in the PM_{10} SIP is 0.110 lb/ton. Therefore, in 2003 the PM_{10} emissions were below this limit (359.2 lb PM_{10}/yr)/(261,933.7 ton/yr) = 0.0014 lb/ton.

SBS Process Emissions

Process Unit	Sulfur Flow (LTPD)	SBS Exhaust	CEMS Data SO_2 Conc.	SO_2[1] (lb/hr)	SO_2 (tpy)	H_2SO_4 Mist	
						lb/hr[1]	tpy
SBS TGU	0.036	337.8	8	0.4	2.0	0.02	0.09

Beavon Stretford Process Emissions

No. of Days Combusting	Actual Airflow MAscf/hr	SO_2[1] lb/hr**	SO_2 tpy	H_2SO_4 Mist		H_2S lb/hr	H_2S tpy	Total Reduced Sulfur lb/hr	Total Reduced Sulfur tpy
				lb/hr[1]	tpy				
199	1,033	7.2	17.1	0.33	0.79	1.1	4.8	12.8	56.1

** The SO_2 concentration is calculated based on average daily H_2S and TRS CEMS Data.

The Beavon Stretford combustor temperature ramps up if the H_2S concentration approaches 10 ppm. BP Whiting has estimated that approximately 30% of the TRS/H2S sulfur is converted to SO_2 after the combustion temperature ramps up.

Sulfur Loading Emissions***

	H_2S Conc. (ppm)	Average Sulfur Stored (LTPD)	H_2S in sulfur (lb/hr)	H_2S in sulfur (ton/yr)	H_2S Emitted (lb/hr)	H_2S Emitted (ton/yr)	
Before Loading	250	323.2	7.6	33.2			
After Loading	200	323.2	6.1	26.5			
					1.5	6.6	

*** The difference in the amount of H_2S in the sulfur before and after loading is assumed to be emitted to atmosphere as part of the loading process.

[1] Hourly emission rate represents annual average hourly emissions.

**** Sulfur pit loading emissions have only been included for the H_2S/TRS baseline years of 2000-2001.

Table C.25. 2004 Sulfur Recovery Complex Emissions

Combustor Emissions

Process Unit	Natural Gas Usage (MMscf/yr)	VOC				NO_X				SO_2				PM (Filterable)				$PM_{10}/PM_{2.5}$ (Filterable + Condensible)				CO				Pb				H_2SO_4 Mist		Hg				Be			
		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
SBS TGU	79.2	5.5	lb/MMscf	0.0	0.2	100	lb/MMscf	0.9	4.0	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.1	0.3	84	lb/MMscf	0.8	3.3	5.00E-04	lb/MMscf	4.5E-06	2.0E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
Beavon-Stretford TGU	48.5	5.5	lb/MMscf	0.0	0.1	100	lb/MMscf	0.6	2.4	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.0	7.6	lb/MMscf	0.0	0.2	84	lb/MMscf	0.5	2.0	5.00E-04	lb/MMscf	2.8E-06	1.2E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000
SRU Incinerator	56.7	5.5	lb/MMscf	0.0	0.2	100	lb/MMscf	0.6	2.8	0.6	lb/MMscf	0.0	0.0	1.9	lb/MMscf	0.0	0.1	7.6	lb/MMscf	0.0	0.2	84	lb/MMscf	0.5	2.4	5.00E-04	lb/MMscf	3.2E-06	1.4E-05	0.000	0.00	1.84E-04	lb/MMscf	0.000	0.0000	1.20E-05	lb/MMscf	0.000	0.0000

* The total flow to the Beavon-Stretford TGU in 2004 was 282,362.3 ton/yr based on data recorded by the BP Whiting PI data collection system.
Note the PM_{10} emission limit provided in the PM_{10} SIP is 0.110 lb/ton. Therefore, in 2004 the PM_{10} emissions were below this limit (368.9 lb PM_{10}/yr)/(282,362.3 ton/yr) = 0.0013 lb/ton.

SBS Process Emissions

Process Unit	Sulfur Flow (LTPD)	SBS Exhaust	CEMS Data SO_2 Conc.	SO_2[1] (lb/hr)	SO_2 (tpy)	H_2SO_4 Mist	
						lb/hr[1]	tpy
SBS TGU	0.083	467.8	14	1.1	5.0	0.05	0.23

Beavon Stretford Process Emissions

No. of Days Combusting	Actual Airflow MAscf/hr	SO_2[1] lb/hr**	SO_2 tpy	H_2SO_4 Mist		H_2S lb/hr	H_2S tpy	Total Reduced Sulfur lb/hr	Total Reduced Sulfur tpy
				lb/hr[1]	tpy				
5	1,267	3.4	0.2	0.16	0.01	0.2	0.7	4.5	19.9

** The SO_2 concentration is calculated based on average daily H_2S and TRS CEMS Data.

The Beavon Stretford combustor temperature ramps up if the H_2S concentration approaches 10 ppm. BP Whiting has estimated that approximately 30% of the TRS/H2S sulfur is converted to SO_2 after the combustion temperature ramps up.

Sulfur Loading Emissions***

	H_2S Conc. (ppm)	Average Sulfur Stored (LTPD)	H_2S in sulfur (lb/hr)	H_2S in sulfur (ton/yr)	H_2S Emitted (lb/hr)	H_2S Emitted (ton/yr)	
Before Loading	250	305.4	7.2	31.4			
After Loading	200	305.4	5.7	25.1			
					1.4	6.3	

*** The difference in the amount of H2S in the sulfur before and after loading is assumed to be emitted to atmosphere as part of the loading process.
[1] Hourly emission rate represents annual average hourly emissions.
**** Sulfur pit loading emissions have only been included for the H_2S/TRS baseline years of 2000-2001.

Table C.26. Project Cooling Tower Emissions

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Existing Unaffected Cooling Towers to be Controlled for PM Emission Reductions

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 2[2]	25,000	gpm	1,285	gpm	1,627	0.001%	1.29E-04	lb/1000 gal	0.2	0.9
Cooling Tower 3	90,000	gpm	1,571	gpm	1,147	0.001%	9.08E-05	lb/1000 gal	0.5	2.2
Cooling Tower 4	44,000	gpm	1,085	gpm	1,645	0.001%	1.30E-04	lb/1000 gal	0.4	1.5

Shutdown Cooling Tower

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
SBS Cooling Tower	-	-	-	-	-	-	-	-	-	-	-	-	-	-

New Cooling Towers

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 7	21,000	gpm	451	gpm	1,163	0.7	lb/MMgal	0.9	3.9	0.001%	9.20E-05	lb/1000 gal	0.1	0.5
Cooling Tower 8	90,000	gpm	2,956	gpm	1,163	0.7	lb/MMgal	3.9	17.1	0.001%	9.20E-05	lb/1000 gal	0.5	2.2
HU Cooling Tower[3]	14,000	gpm	0	gpm	6,300					0.001%	4.99E-04	lb/1000 gal	0.42	1.8

[1] Hourly emission rate represents annual average hourly emissions.
[2] Half of the Cooling Tower 2 modules were controlled prior to the CXHO Project. Contemporaneous to the CXHO Project the other modules will be controlled with high efficiency drift eliminators. Note the recirculation rate used in this calculation is half of the total Cooling Tower recirculation rate.
[3] The new hydrogen unit cooling tower will be operated separately from refinery operations. VOC emissions are only applicable to cooling towers serving petroleum refinery operations.

Cooling Tower VOC Emission Calculation

$$VOC\ \ Emissions\ \ = (R + M) * EF_{AP-42}$$

Where,
R = Recirculation rate (1,000 gal/min)
M = Make-up rate (1,000 gal/min)

$$Make\ -Up\ \ Rate\ = M_{AVG} * \frac{R_N}{R_{AVG}}$$

Where,
M_{AVG} = Average make-up rate for existing cooling towers 1 through 6 (gpm)
R_N = Recirculation rate for new cooling tower (gpm)
R_{AVG} = Average recirculation rate for existing cooling towers 1 through 6 (gpm)

Cooling Tower $PM/PM_{10}/PM_{2.5}$ Emission Factor Calculation

$$PM\ /\ PM_{10}\ /\ PM_{2.5}\ EF\ = PM\ \ EF_{AP-42} * \frac{TLD_{design}}{TLD_{AP-42}} * \frac{TDS_{future}}{TDS_{AP-42}}$$

Where,
PM EF_{AP-42} = AP-42 Emission Factor for PM10 (lb/1000 gal)
TLD_{design} = Design total liquid drift (%)
TLD_{AP-42} = Design total liquid drift (%)
TDS_{future} = Estimated future total dissolved solid content (mg/L)
TDS_{AP-42} = Total dissolved solid content used in AP-42 (mg/L)

Cooling Tower $PM/PM_{10}/PM_{2.5}$ Emission Calculation

$$PM\ /\ PM_{10}\ /\ PM_{2.5}\ = (R + M) * PM\ \ EF$$

Where,
R = Recirculation rate (1,000 gal/min)
M = Make-up rate (1,000 gal/min)

Table C.27. 2000 Cooling Tower Emissions

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Existing Unaffected Cooling Towers to be Controlled for PM Emission Reductions

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 2[2]	25,000	gpm	1,248	gpm	1,748	0.02%	2.77E-03	lb/1000 gal	4.2	18.2
	25,000	gpm	1,248	gpm	1,748	0.001%	1.38E-04	lb/1000 gal	0.2	0.9
Cooling Tower 3	90,000	gpm	1,459	gpm	728	0.02%	1.15E-03	lb/1000 gal	6.2	27.3
Cooling Tower 4	44,000	gpm	1,085	gpm	1,018	0.02%	1.61E-03	lb/1000 gal	4.3	18.6

Shutdown Cooling Tower

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
SBS Cooling Tower[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Hourly emission rate represents annual average hourly emissions.
[2] Only half of the Cooling Tower 2 modules were controlled by high efficiency drift eliminators in 2000.
[3] Unit was not operated during the 2000 baseline year.

Table C.28. 2001 Cooling Tower Emissions

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Existing Unaffected Cooling Towers to be Controlled for PM Emission Reductions

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 2[2]	25,000	gpm	1,248	gpm	1,413	0.02%	2.24E-03	lb/1000 gal	3.4	14.7
	25,000	gpm	1,248	gpm	1,413	0.001%	1.12E-04	lb/1000 gal	0.2	0.7
Cooling Tower 3	90,000	gpm	1,459	gpm	798	0.02%	1.26E-03	lb/1000 gal	6.8	29.9
Cooling Tower 4	44,000	gpm	1,085	gpm	829	0.02%	1.31E-03	lb/1000 gal	3.5	15.2

Shutdown Cooling Tower

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
SBS Cooling Tower	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Hourly emission rate represents annual average hourly emissions.
[2] Only half of the Cooling Tower 2 modules were controlled by high efficiency drift eliminators in 2001.
[3] Unit was not operated during the 2001 baseline year.

Table C.29. 2002 Cooling Tower Emissions

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Existing Unaffected Cooling Towers to be Controlled for PM Emission Reductions

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 2[2]	25,000	gpm	1,248	gpm	1,627	0.02%	2.58E-03	lb/1000 gal	3.9	16.9
	25,000	gpm	1,248	gpm	1,627	0.001%	1.29E-04	lb/1000 gal	0.2	0.8
Cooling Tower 3	90,000	gpm	1,459	gpm	1,001	0.02%	1.58E-03	lb/1000 gal	8.6	37.5
Cooling Tower 4	44,000	gpm	1,085	gpm	1,221	0.02%	1.93E-03	lb/1000 gal	5.1	22.4

Shutdown Cooling Tower

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
SBS Cooling Tower	4,100	gpm	91	gpm	958	0.7	lb/MMgal	0.2	0.8	0.02%	1.52E-03	lb/1000 gal	0.4	1.6

[1] Hourly emission rate represents annual average hourly emissions.

[2] Only half of the Cooling Tower 2 modules were controlled by high efficiency drift eliminators in 2002.

Table C.30. 2003 Cooling Tower Emissions

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Existing Unaffected Cooling Towers to be Controlled for PM Emission Reductions

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 2[2]	25,000	gpm	1,248	gpm	1,425	0.02%	2.26E-03	lb/1000 gal	3.4	14.8
	25,000	gpm	1,248	gpm	1,425	0.001%	1.13E-04	lb/1000 gal	0.2	0.7
Cooling Tower 3	90,000	gpm	1,459	gpm	1,126	0.02%	1.78E-03	lb/1000 gal	9.6	42.2
Cooling Tower 4	44,000	gpm	1,085	gpm	1,153	0.02%	1.83E-03	lb/1000 gal	4.8	21.1

Shutdown Cooling Tower

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
SBS Cooling Tower	4,100	gpm	91	gpm	958	0.7	lb/MMgal	0.2	0.8	0.02%	1.52E-03	lb/1000 gal	0.4	1.6

[1] Hourly emission rate represents annual average hourly emissions.

[2] Only half of the Cooling Tower 2 modules were controlled by high efficiency drift eliminators in 2003.

Table C.31. 2004 Cooling Tower Emissions

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Existing Unaffected Cooling Towers to be Controlled for PM Emission Reductions

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower 2[2]	25,000	gpm	1,285	gpm	1,596	0.02%	2.53E-03	lb/1000 gal	3.8	16.6
	25,000	gpm	1,285	gpm	1,596	0.001%	1.26E-04	lb/1000 gal	0.2	0.8
Cooling Tower 3	90,000	gpm	1,571	gpm	1,147	0.02%	1.82E-03	lb/1000 gal	9.8	43.0
Cooling Tower 4	44,000	gpm	1,042	gpm	1,645	0.02%	2.60E-03	lb/1000 gal	6.9	30.1

Shutdown Cooling Tower

Process Unit	Recirculation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	VOC				$PM/PM_{10}/PM_{2.5}$				
						EF	Unit	lb/hr[1]	tpy	% Liquid Drift	EF	Unit	lb/hr[1]	tpy
SBS Cooling Tower	4,100	gpm	155	gpm	825	0.7	lb/MMgal	0.2	0.8	0.02%	1.31E-03	lb/1000 gal	0.3	1.4

[1] Hourly emission rate represents annual average hourly emissions.

[2] Only half of Cooling Tower 2 modules were controlled by high efficiency drift eliminators in 2004.

Table C.32. Project Fugitive Dust Emissions - Coke Handling

Aggregate Handling - Normal Operating Scenario

Total Coke Handled	2,080,500	tons/yr
Transfer Points	10	
Percentage of Operating Time[1]	95%	

Emission Calculation Variables	PM	$PM_{10}/PM_{2.5}$	Unit
Particle Size Multiplier (k)[2]	0.74	0.35	
Average Wind Speed in NW Indiana[3] (U)	10.4	10.4	mph
Material Moisture Content for Transfer Points (M)[4]	8	8	%
Percent Control for Transfer Point[5] 1, 10	70	70	%
Percent Control for Transfer Points[6] 2 through 9	90	90	%

Emission Calculation

Coke Handling	PM		PM_{10}		$PM_{2.5}$	
	lb/hr[7]	tpy	lb/hr[7]	tpy	lb/hr[7]	tpy
Transfer Points 1, 10	0.1	0.5	0.1	0.3	0.1	0.3
Transfer Points 2 - 9	0.2	0.7	0.1	0.3	0.1	0.3

$$EF = k * 0.0032 * \frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}} \left(\frac{\text{lb PM}}{\text{ton coke handled}}\right)$$

[1] Percentage of operating time in normal and emergency scenarios provided by coke handling contract
[2] Emission factors provided in AP-42 Section 13.2.4 (January 1995).
[3] Based on average annual wind speed for Chicago, IL in U.S. EPA TANKS 4.0.9d.
[4] Based on assumed worst case moisture content of petroleum coke
[5] Percentage control provided by enclosed conveyors and water spray
[6] Percentage control provided by enclosed building and water spray.
[7] Hourly emission rate represents annual average hourly emissions.

Table C.33. Project Fugitive Dust Emissions - Coke Handling (Alternate Operating Scenario)

Aggregate Handling - Emergency Operation Scenario

Total Coke Handled	109,500	tons/yr
Transfer Points	4	
Percentage of Operating Time[1]	5%	

Emission Calculation Variables	PM	$PM_{10}/PM_{2.5}$	Unit
Particle Size Multiplier (k)[2]	0.74	0.35	
Average Wind Speed in NW Indiana[3](U)	10.4	10.4	mph
Material Moisture Content for Transfer Points (M)[4]	8	8	%
Percent Control for Transfer Points[5] 1, 2, 3	40	40	%
Percent Control for Transfer Point[6] 4	0	0	%

Emission Calculation

Coke Handling	PM		PM_{10}		$PM_{2.5}$	
	lb/hr[7]	tpy	lb/hr[7]	tpy	lb/hr[7]	tpy
Transfer Point 1, 2, 3	0.020	0.087	0.009	0.041	0.009	0.041
Transfer Point 4	0.011	0.048	0.005	0.023	0.005	0.023

$$EF = k * 0.0032 * \frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}} \left(\frac{\text{lb PM}}{\text{ton coke handled}}\right)$$

[1] Percentage of operating time in normal and emergency scenarios provided by coke handling contractor
[2] Emission factors provided in AP-42 Section 13.2.4 (January 1995).
[3] Based on average annual wind speed for Chicago, IL in U.S. EPA TANKS 4.0.9d.
[4] Based on assumed worst case moisture content of petroleum coke
[5] Percentage control provided by enclosed conveyors
[6] No control for transfer into rail cars assumed for emergency operating scenario
[7] Hourly emission rate represents annual average hourly emissions.

Table C.34. 2001-2002 Coke Storage Emissions

Coke Aggregate Storage

Average Tons of Coke Produced per day[1]	1,638.9	tons/day
Average Tons of Coke Stored per pile/day (coke shipped out 5 days per week)	2,300.8	tons/day
Average Pile Height	14	ft
Density of Coke	56	lb/ft^3
Pile 3A Exposed Surface Area[2]	0.40	acres
Pile 3B Exposed Surface Area[2]	0.40	acres
Total Coke Yard Surface Area[3]	2.24	acres

Emission Calculation Variables[4]	PM	PM_{10}[5]	$PM_{2.5}$[6]	Unit
Pile Silt Content of Aggregate (s)[7]	4.5	4.5	4.5	%
Yard Silt Content of Aggregate (s)[8]	10.4	10.4	10.4	%
Number of days with greater then 0.01 in. of precipitation per year (p)[9]	124	124	124	days
% of time the unobstructed wind speed exceeds 12 mph (f)[10]	33.4	33.4	33.4	%

Emission Calculation

Coke Storage	PM		PM_{10}		$PM_{2.5}$	
	lb/hr[11]	tpy	lb/hr[11]	tpy	lb/hr[11]	tpy
Pile 3A	0.2	0.9	0.1	0.4	0.1	0.4
Pile 3B	0.2	0.9	0.1	0.4	0.1	0.4
Coke Yard	2.5	11.0	1.3	5.5	1.3	5.5

[1] Average tons of coke produced per day based on annual coke production (on a dry basis) in 2001 and 2002, which was 1,138,511,050 and 1,036,797,400 lb/yr, respectively, adjusted to 10% moisture.

[2] Pile surface area is estimated based on the production of coke and pile height.

$$\text{Coke Produced}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Amount of Coke Produced}\left(\frac{\text{ton}}{\text{day}}\right) * 365\ \frac{\text{day}}{\text{yr}}$$

$$\text{Days Coke Loaded} = 5\ \frac{\text{days}}{\text{week}} * 52\ \frac{\text{weeks}}{\text{yr}} = 260\ \frac{day}{yr}$$

$$\text{Average Coke Stored}\left(\frac{\text{ton}}{\text{day}}\right) = \frac{\text{Coke Produced}\left(\frac{\text{ton}}{\text{yr}}\right)}{260\ \frac{\text{day}}{\text{yr}}}$$

$$\text{Volume of Coke Stored}\left(\text{ft}^3\right) = \text{Average Coke Stored}\left(\frac{\text{ton}}{\text{day}}\right) * \frac{2{,}000\ \text{lb}}{1\ \text{ton}} * \frac{\text{ft}^3}{56\ \text{lb}}$$

$$\text{Volume of Cone} = \frac{1}{3}\pi r^2 h$$

$$\text{Radius of Pile} = \sqrt{\left(\frac{3 * 71{,}296.36\ \text{ft}^3}{\pi * 14\ \text{ft}}\right)} = 69.73\ \text{ft}$$

$$\text{Exposed Pile Surface Area}\left(\text{acre}\right) = \pi * r^2 * \frac{1\ \text{acre}}{43{,}560\ \text{ft}^2}$$

[3] Coke yard surface area estimated from aerial image of coke yard.

[4] Based on Chapter 4 of the 1988 EPA Report "Control of Open Fugitive Dust Sources". (EPA - 450/3-88-008) The following equation calculated particulate emissions due to wind erosion of an continuously active pile.

$$EF = 1.7\left(\frac{s}{1.5}\right)\left(\frac{365-p}{235}\right)\left(\frac{f}{15}\right)\left(\frac{1\ \text{day}}{24\ \text{hour}}\right) \quad (\text{lb/hr/acre})$$

[5] The PM_{10} emission factor is estimated to be half of the PM emission factor based on 1988 EPA Report (EPA - 450/3-88-008).

[6] The $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

[7] Surface material silt content for storage pile from silt testing done on comparable coke pile.

[8] Surface material silt content for coke yard from silt testing on comparable coke yard.

[9] The number of wet days with at least 0.01 inches of precipitation is based on a 47 year average for Chicago, IL from the National Climate Data Center.

[10] Based on four years (1997-2001) of metrological data at Midway Airport.

[11] Hourly emission rate represents annual average hourly emissions.

Table C.35. 2001-2002 Coke Handling Emissions

Coke Aggregate Handling

Average Tons of Coke Produced per day	1,638.9	tons/day
Total Coke Handled[1]	598,210	ton/yr
Transfer Points[2]	3	

Emission Calculation Variables[3]	PM	$PM_{10}/PM_{2.5}$	Unit
Particle Size Multiplier (k)	0.74	0.35	
Average Wind Speed in NW Indiana (U)[4]	10.4	10.4	mph
Material Moisture Content (M)[5]	10	10	%

Emission Calculation

Coke Handling	PM		PM_{10}		$PM_{2.5}$[7]	
	lb/hr[6]	tpy	lb/hr[6]	tpy	lb/hr[6]	tpy
Total for Three Transfer Points	0.1	0.6	0.06	0.3	0.1	0.3

$$EF = k * 0.0032 * \frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}} \left(\frac{\text{lb PM}}{\text{ton coke handled}}\right)$$

Footnotes:

[1] Total coke handled based on average daily production during the baseline period.

$$\text{Total Coke Handled}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Average Coke Production}\left(\frac{\text{ton}}{\text{day}}\right) * 365\,\frac{\text{day}}{\text{yr}}$$

[2] The current coke handling includes three transfer points: (1) the drop into storage pile 3A or 3B from the front end loader (FEL), (2) loading out of storage pile 3A or 3B by a FEL, and (3) the drop into the truck from the FEL.

[3] Emission factors provided in AP-42 Section 13.2.4 (November 2006).

[4] Based on average annual wind speed for Chicago, IL in U.S. EPA TANKS 4.0.9d.

[5] Based on average moisture content for coke material handled provided by Natalie Grimmer via email on 1/4/2007.

[6] Hourly emission rate represents annual average hourly emissions.

[7] The $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

Table C.36. 2001-2002 Fugitive Emissions from Paved Roads

Coke Fugitive Dust from Paved Roads

Average Tons of Coke Produced per day	1,638.9	tons/day
Average Tons of Coke per Truck	21.5	ton/truck
Miles Driven Per Truck at Refinery	1.6	miles/truck
Vehicle Miles Traveled by Average Truck[1]	44,518	VMT/yr

Emission Calculation Variables[2]	PM	$PM_{10}/PM_{2.5}$	Unit
Particle Size Multiplier (k)[3]	0.082	0.016	lb/VMT
Road Surface Silt Loading (sL)[4]	9.7	9.7	g/m^2
Average Weight of Vehicles on Roads (W)[5]	25.8	25.8	ton
Number of Wet Days with at Least 0.01 in. of Precipitation (P)[6]	124	124	days
Number of Days in Averaging Period (N)	365	365	days
Emission Factor for Exhaust, Brake Wear and Tire Wear (C)[7]	0.00047	0.00047	lb/VMT

Emission Calculation

Paved Road Emissions	PM		PM_{10}		$PM_{2.5}$[9]	
	lb/hr[8]	tpy	lb/hr[8]	tpy	lb/hr[8]	tpy
Average Truck	26.8	117.2	5.2	22.9	5.2	22.9

$$EF = \left[k\left(\frac{sL}{2}\right)^{0.65}\left(\frac{W}{3}\right)^{1.5} - C \right]\left(1 - \frac{P}{4N}\right) \quad (\text{lb/VMT})$$

Footnotes:

[1] Each truck travels a total of 1.6 miles within the Whiting Refinery on paved and swept roads.

$$\text{Vehicle Miles Traveled}\left(\frac{\text{VMT}}{\text{yr}}\right) = \frac{\text{Average Coke Production}\left(\frac{\text{ton}}{\text{day}}\right) * 365\,\frac{\text{day}}{\text{yr}}}{\text{Average Coke Loaded on Each Truck}\left(\frac{\text{ton}}{\text{truck}}\right)} * \text{Miles Traveled}\left(\frac{\text{miles}}{\text{truck}}\right)$$

[2] Emission factors provided in AP-42 Section 13.2.1 (November 2006).

[3] Particle size multiplier k from AP-42 Table 13.2.1-1 (November 2006).

[4] Road surface silt loading is from Table 13.2.1-4 and is based on the average silt loading for the iron and steel production industry.

[5] Since each truck travels 0.8 miles unloaded (weighing 15 tons) and 0.8 miles loaded (weighing 36.5 tons), the the average truck weight is 25.8 tons.

[6] The number of wet days with at least 0.01 inches of precipitation is based on a 47 year average for Chicago, IL from the National Climate Data Center.

[7] The emission factor for vehicle fleet exhaust, break and tire wear is from AP-42 Table 13.2.1-2 (November 2006).

[8] Hourly emission rate represents annual average hourly emissions.

[9] The $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

Table C.37. 2001-2002 Fugitive Emissions from Unpaved Roads

Coke Fugitive Dust from Unpaved Roads

Average Tons of Coke Produced per day	1,638.9	tons/day
Average Tons of Coke per Truck	21.5	ton/truck
Feet Driven Per Truck within Coke Yard	640	feet/truck
Feet Driven Per Front End Loader (FEL)	1,320	FEL feet driven/truck
Vehicle Miles Traveled by Average Trucks[1]	3,373	VMT/yr
Vehicle Miles Traveled by Average FEL[1]	6,956	VMT/yr

Emission Calculation Variables[2]	PM	PM_{10}	Unit
Empirical Constant (k)[3]	4.9	1.5	lb/VMT
Empirical Constant (a)[3]	0.7	0.9	
Empirical Constant (b)[3]	0.45	0.45	
Surface Material Silt Content (s)[4]	10.4	10.4	%
Average Weight of Trucks on Roads (W)[5]	25.8	25.8	ton
Average Weight of FEL on Roads (W)[6]	48.4	48.4	ton
Number of Wet Days with at Least 0.01 in. of Precipitation (P)[7]	124	124	%
Number of Days in Averaging Period (N)	365	365	days

Emission Calculation

Paved Road Emissions	PM		PM_{10}		$PM_{2.5}$[9]	
	lb/hr[8]	tpy	lb/hr[8]	tpy	lb/hr[8]	tpy
Average Truck	3.0	13.0	0.9	3.9	0.9	3.9
Average Front End Loader	8.1	35.6	2.4	10.6	2.4	10.6

$$EF = \left(k\left(\frac{s}{12}\right)^{a}\left(\frac{W}{3}\right)^{b}\right)\left(\frac{N-P}{N}\right) \quad (lb/VMT)$$

Footnotes:

[1] Each truck travels either 360 ft (Pile 3A) or 280 ft (Pile 3B) each way to and from the coke pile inside the coke yard.

$$\text{Vehicle Miles Traveled}\left(\frac{VMT}{yr}\right) = \frac{\text{Average Coke Production}\left(\frac{ton}{day}\right) * 365\ \frac{day}{yr}}{\text{Average Coke Loaded on Each Truck}\left(\frac{ton}{truck}\right)} * \text{Feet Traveled}\left(\frac{feet}{truck}\right) * \frac{1\ mile}{5{,}280\ feet}$$

Note the FEL vehicle miles traveled are similarly calculated assuming either 460 ft (Pile 3A) or 120 ft (Pile 3B) of distance from the coker to the coke pile and an additional 40 ft of distance between the 3A or 3B coke pile and the truck being loaded. Note that given the capacity of the FEL relative to the trucks, each FEL trip must be made twice per each truck loaded.

[2] Emission factors provided in AP-42 Section 13.2.2 (November 2006).

[3] Emission constants k, a, and b from AP-42 Table 13.2.2-2.

[4] Surface material silt content from silt testing performed at comparable coke yard.

[5] Since each truck travels the same distance unloaded (weighing 15 tons) and loaded (weighing 36.5 tons), the the average truck weight is 25.8 tons.

[5] Since each FEL travels the same distance unloaded (weighing 42.1 tons) and loaded (weighing 54.6 tons), the the average FEL weight is 48.4 tons.

[6] The number of wet days with at least 0.01 inches of precipitation is based on a 47 year average for Chicago, IL from the National Climate Data Center.

[7] Hourly emission rate represents annual average hourly emissions.

[8] The $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

Table C.38. Project Flare Pilot and Purge Gas Combustion Emissions (Normal Operation)

Process			VOC				NO_X				SO_2				PM				$PM_{10}/PM_{2.5}$ (filterable + condensable)				CO				Pb				H_2SO_4 Mist		Hg				Be			
Unit	Pilot Rates		EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
GOHT Flare	420	scfh	5.5	lb/MMscf	0.0	0.01	100	lb/MMscf	0.0	0.2	0.60	lb/MMscf	0.0	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.01	84	lb/MMscf	0.0	0.2	5.0E-04	lb/MMscf	2.1E-07	9.2E-07	0.00	0.00	1.8E-04	lb/MMscf	7.7E-08	3.4E-07	1.2E-05	lb/MMscf	5.0E-09	2.2E-08
South Flare	420	scfh	5.5	lb/MMscf	0.0	0.01	100	lb/MMscf	0.0	0.2	0.60	lb/MMscf	0.00	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.01	84	lb/MMscf	0.0	0.2	5.0E-04	lb/MMscf	2.1E-07	9.2E-07	0.00	0.00	1.8E-04	lb/MMscf	7.7E-08	3.4E-07	1.2E-05	lb/MMscf	5.0E-09	2.2E-08
HU Flare	255	scfh	5.5	lb/MMscf	0.0	0.01	100	lb/MMscf	0.0	0.1	0.60	lb/MMscf	0.00	0.00	1.9	lb/MMscf	0.0	0.002	7.6	lb/MMscf	0.0	0.0	84	lb/MMscf	0.0	0.1	5.0E-04	lb/MMscf	1.3E-07	5.6E-07	0.00	0.00	1.8E-04	lb/MMscf	4.7E-08	2.1E-07	1.2E-05	lb/MMscf	3.1E-09	1.3E-08

Process			VOC				NO_X				SO_2				PM				$PM_{10}/PM_{2.5}$ (filterable + condensable)				CO				Pb				H_2SO_4 Mist		Hg				Be			
Unit	Purge Rates		EF	Unit	lb/hr[1]	tpy[2]	EF	Unit	lb/hr[1]	tpy[2]	EF[3]	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy[2]	EF	Unit	lb/hr[1]	tpy[2]	EF	Unit	lb/hr[1]	tpy[2]	EF	Unit	lb/hr[1]	tpy[2]	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy[2]	EF	Unit	lb/hr[1]	tpy[2]
GOHT Flare	2,820	scfh	0.14	lb/MMBtu	0.5	2.1	0.068	lb/MMBtu	0.2	1.0	13.30	lb/MMscf	0.0	0.2	1.9	lb/MMscf	0.0	0.02	7.6	lb/MMscf	0.0	0.1	0.37	lb/MMBtu	1.3	5.5	5.0E-04	lb/MMscf	1.7E-06	7.3E-06	0.00	0.01	1.8E-04	lb/MMscf	6.1E-07	2.7E-06	1.2E-05	lb/MMscf	6.1E-07	2.7E-06
South Flare	3,300	scfh	0.14	lb/MMBtu	0.6	2.4	0.068	lb/MMBtu	0.3	1.2	13.30	lb/MMscf	0.04	0.2	1.9	lb/MMscf	0.0	0.03	7.6	lb/MMscf	0.0	0.1	0.37	lb/MMBtu	1.5	6.4	5.0E-04	lb/MMscf	1.9E-06	8.5E-06	0.00	0.01	1.8E-04	lb/MMscf	1.9E-06	8.5E-06	1.2E-05	lb/MMscf	1.9E-06	8.5E-06

1. Hourly emission rate represents annual average hourly emissions.
2. Calculation accounts for annual average design refinery fuel gas higher heating value of 1,203.3 Btu/scf.
3. Emission factor accounts for annual average design refinery fuel gas total sulfur concentration of 80 ppm.
4. The HU Flare will not be designed with a purge. Therefore, no purging emissions are included.

Table C.39. Fugitive Emission Factors

Equipment/Service	EPA Refinery Average Emission Factors		EPA Refinery SCREEING Emission Factors - LEAK		EPA Refinery SCREEING Emission Factors - NO LEAK	
	Kg/hr/source	**lbs/hr/source**	**Kg/hr/source**	**lbs/hr/source**	**Kg/hr/source**	**lbs/hr/source**
Valves						
Gas/Vapor	0.0268	0.059083816	0.2626	0.5789	0.0006	0.0013
Light Liquid	0.0109	0.024030358	0.0852	0.1878	0.0017	0.0037
Heavy Liquid	0.00023	0.000507063	0.00023	0.00051	0.00023	0.00051
Pumps						
Light Liquid	0.114	0.25132668	0.437	0.963	0.012	0.0265
Heavy Liquid	0.021	0.04629702	0.3885	0.8565	0.0135	0.02976
Flanges						
Gas/Vapor	0.00025	0.00055	0.0375	0.0827	0.00006	0.00013
Light Liquid	0.00025	0.00055	0.0375	0.0827	0.00006	0.00013
Heavy Liquid	0.00025	0.00055	0.0375	0.0827	0.00006	0.00013
Compressors	0.636	1.40214	1.608	3.545	0.0894	0.1971
Relief Valves	0.16	0.35274	1.691	3.728	0.0447	0.0985
Open-ended Lines	0.0023	0.00507	0.01195	0.02635	0.0015	0.0033
Sampling Connections	0.015	0.03307	0.0375	0.0827	0.00006	0.00013

Reference:

A Factors are taken from EPA Document EPA-453/R-95-017, Nov. 1995, Table 2-2, Page 2-13.

B Factors are taken from EPA Document EPA-453/R-95-017, Nov. 1995, Table 2-6, Page 2-20.

Table C.40. Fugitive Emission Calculations for 4 Ultraformer (4UF)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	56	0.5789	0.0013	2.0%	0.7197	95%	100%	0.16
Light Liquid	13	0.1878	0.0037	2.0%	0.0960	95%	100%	0.02
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	113	0.0827	0.00013	0.3%	0.0427	30%	100%	0.13
Light Liquid	6	0.0827	0.00013	0.3%	0.0023	30%	100%	0.01
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	1	3.728	0.0985	2.0%	0.1711	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.32**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.41. Fugitive Emission Calculations for 3 Ultraformer (3UF)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	-887	0.5789	0.0013	2.0%	-11.3997	95%	100%	-2.50
Light Liquid	-744	0.1878	0.0037	2.0%	-5.4922	95%	100%	-1.20
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	-11	0.963	0.0265	2.0%	-0.4975	80%	100%	-0.44
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	-1,912	0.0827	0.00013	0.3%	-0.7222	30%	100%	-2.21
Light Liquid	-2,828	0.0827	0.00013	0.3%	-1.0682	30%	100%	-3.27
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	-1	3.545	0.1971	2.0%	-0.2640	0%	100%	-1.16
Relief Valves	-13	3.728	0.0985	2.0%	-2.2242	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	-1	0.0827	0.00013	2.0%	-0.0018	0%	100%	-0.01
							Total VOC Emissions (tons/yr):	**-10.79**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.42. Fugitive Emission Calculations for 12 Pipestill (12PS)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	114	0.5789	0.0013	2.0%	1.4651	95%	100%	0.32
Light Liquid	197	0.1878	0.0037	2.0%	1.4543	95%	100%	0.32
Heavy Liquid	394	0.00051	0.00051	2.0%	0.2009	30%	100%	0.62
Pumps								
Light Liquid	3	0.963	0.0265	2.0%	0.1357	80%	100%	0.12
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	456	0.0827	0.00013	0.3%	0.1722	30%	100%	0.53
Light Liquid	788	0.0827	0.00013	0.3%	0.2976	30%	100%	0.91
Heavy Liquid	1,576	0.0827	0.00013	0.3%	0.5953	30%	100%	1.83
Compressors	1	3.545	0.1971	2.0%	0.2640	0%	100%	1.16
Relief Valves	6	3.728	0.0985	2.0%	1.0265	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**5.80**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.43. Fugitive Emission Calculations for Distillate Hydrotreater (DHT)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	99	0.5789	0.0013	2.0%	1.2723	95%	100%	0.28
Light Liquid	51	0.1878	0.0037	2.0%	0.3765	95%	100%	0.08
Heavy Liquid	33	0.00051	0.00051	2.0%	0.0168	30%	100%	0.05
Pumps								
Light Liquid	1	0.963	0.0265	2.0%	0.0452	80%	100%	0.04
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	105	0.0827	0.00013	0.3%	0.0397	30%	100%	0.12
Light Liquid	16	0.0827	0.00013	0.3%	0.0060	30%	100%	0.02
Heavy Liquid	24	0.0827	0.00013	0.3%	0.0091	30%	100%	0.03
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	4	3.728	0.0985	2.0%	0.6844	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.62**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.44. Fugitive Emission Calculations for New Coker (#2 Coker)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	1,367	0.5789	0.0013	2.0%	17.5687	95%	100%	3.85
Light Liquid	1,367	0.1878	0.0037	2.0%	10.0912	95%	100%	2.21
Heavy Liquid	3,498	0.00051	0.00051	2.0%	1.7840	30%	100%	5.47
Pumps								
Light Liquid	16	0.963	0.0265	2.0%	0.7237	80%	100%	0.63
Heavy Liquid	8	0.8565	0.02976	2.0%	0.3704	80%	100%	0.32
Flanges								
Gas/Vapor	2,196	0.0827	0.00013	0.3%	0.8295	30%	100%	2.54
Light Liquid	2,196	0.0827	0.00013	0.3%	0.8295	30%	100%	2.54
Heavy Liquid	5,802	0.0827	0.00013	0.3%	2.1915	30%	100%	6.72
Compressors	1	3.545	0.1971	2.0%	0.2640	0%	100%	1.16
Relief Valves	30	3.728	0.0985	2.0%	5.1327	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	16	0.0827	0.00013	2.0%	0.0285	0%	100%	0.12
							Total VOC Emissions (tons/yr):	**25.57**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.45. Fugitive Emission Calculations for Existing Coker (11B PS)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	-1,094	0.5789	0.0013	2.0%	-14.0601	95%	100%	-3.08
Light Liquid	-1,094	0.1878	0.0037	2.0%	-8.0759	95%	100%	-1.77
Heavy Liquid	-2,798	0.00051	0.00051	2.0%	-1.4270	30%	100%	-4.38
Pumps								
Light Liquid	-13	0.963	0.0265	2.0%	-0.5880	80%	100%	-0.52
Heavy Liquid	-6	0.8565	0.02976	2.0%	-0.2778	30%	100%	-0.85
Flanges								
Gas/Vapor	-1,757	0.0827	0.00013	0.3%	-0.6636	30%	100%	-2.03
Light Liquid	-1,757	0.0827	0.00013	0.3%	-0.6636	30%	100%	-2.03
Heavy Liquid	-4,642	0.0827	0.00013	0.3%	-1.7533	30%	100%	-5.38
Compressors	-1	3.545	0.1971	2.0%	-0.2640	0%	100%	-1.16
Relief Valves	-24	3.728	0.0985	2.0%	-4.1062	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	-13	0.0827	0.00013	2.0%	-0.0232	0%	100%	-0.10
							Total VOC Emissions (tons/yr):	**-21.29**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.46. Fugitive Emission Calculations for Gas Oil Hydrotreater (GOHT)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	915	0.5789	0.0013	2.0%	11.7596	95%	100%	2.58
Light Liquid	912	0.1878	0.0037	2.0%	6.7324	95%	100%	1.47
Heavy Liquid	1,380	0.00051	0.00051	2.0%	0.7038	30%	100%	2.16
Pumps								0.00
Light Liquid	8	0.963	0.0265	2.0%	0.3618	80%	100%	0.32
Heavy Liquid	1	0.8565	0.02976	2.0%	0.0463	80%	100%	0.04
Flanges								0.00
Gas/Vapor	3,660	0.0827	0.00013	0.3%	1.3824	30%	100%	4.24
Light Liquid	3,648	0.0827	0.00013	0.3%	1.3779	30%	100%	4.22
Heavy Liquid	7,475	0.0827	0.00013	0.3%	2.8234	30%	100%	8.66
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	26	3.728	0.0985	2.0%	4.4483	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**23.68**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.47. Fugitive Emission Calculations for New Hydrogen Unit (3rd Party SMR)

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	692	0.5789	0.0013	2.0%	8.8936	95%	100%	1.95
Light Liquid	219	0.1878	0.0037	2.0%	1.6167	95%	100%	0.35
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	6	0.963	0.0265	2.0%	0.2714	80%	100%	0.24
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	2,768	0.0827	0.00013	0.3%	1.0455	30%	100%	3.21
Light Liquid	876	0.0827	0.00013	0.3%	0.3309	30%	100%	1.01
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	15	3.728	0.0985	2.0%	2.5664	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**6.76**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.48. Fugitive Emission Calculations for OSBL

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	53	0.5789	0.0013	2.0%	0.6812	95%	100%	0.15
Light Liquid	53	0.1878	0.0037	2.0%	0.3912	95%	100%	0.09
Heavy Liquid	26	0.00051	0.00051	2.0%	0.0133	30%	100%	0.04
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	212	0.0827	0.00013	0.3%	0.0801	30%	100%	0.25
Light Liquid	212	0.0827	0.00013	0.3%	0.0801	30%	100%	0.25
Heavy Liquid	104	0.0827	0.00013	0.3%	0.0393	30%	100%	0.12
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.89**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.49. Fugitive Emission for Sulfur Recovery Complex

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	73	0.5789	0.0013	2.0%	0.9382	95%	100%	0.21
Light Liquid	11	0.1878	0.0037	2.0%	0.0812	95%	100%	0.02
Heavy Liquid	22	0.00051	0.00051	2.0%	0.0112	30%	100%	0.03
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	292	0.0827	0.00013	0.3%	0.1103	30%	100%	0.34
Light Liquid	44	0.0827	0.00013	0.3%	0.0166	30%	100%	0.05
Heavy Liquid	88	0.0827	0.00013	0.3%	0.0332	30%	100%	0.10
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	2	3.728	0.0985	2.0%	0.3422	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							VOC Emissions w/o Amine Unit (tons/yr):	**0.75**
							Amine Unit Emissions (tons/year):	**1.72**
							Total VOC Emissions (tons/year):	**2.46**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.50. Fugitive Emission for Claus Offgas Treater 1

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	0	0.1878	0.0037	2.0%	0.0000	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							VOC Emissions w/o Amine Unit (tons/yr):	**0.00**
							Amine Unit Emissions (tons/year):	**0.86**
							Total VOC Emissions (tons/year):	**0.86**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.51. Fugitive Emission for Claus Offgas Treater 2

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	0	0.1878	0.0037	2.0%	0.0000	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							VOC Emissions w/o Amine Unit (tons/yr):	**0.00**
							Amine Unit Emissions (tons/year):	**0.86**
							Total VOC Emissions (tons/year):	**0.86**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.52. Fugitive Emission for No 4 Treatment Plant

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	-5	0.5789	0.0013	2.0%	-0.0643	95%	100%	-0.01
Light Liquid	-59	0.1878	0.0037	2.0%	-0.4355	95%	100%	-0.10
Heavy Liquid	-10	0.00051	0.00051	2.0%	-0.0051	30%	100%	-0.02
Pumps								
Light Liquid	-1	0.963	0.0265	2.0%	-0.0452	80%	100%	-0.04
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	-20	0.0827	0.00013	0.3%	-0.0076	30%	100%	-0.02
Heavy Liquid	-40	0.0827	0.00013	0.3%	-0.0151	30%	100%	-0.05
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	-1	3.728	0.0985	2.0%	-0.1711	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**-0.23**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.53. Fugitive Emission for ARU

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	26	0.5789	0.0013	2.0%	0.3342	95%	100%	0.07
Light Liquid	94	0.1878	0.0037	2.0%	0.6939	95%	100%	0.15
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	17	0.0827	0.00013	0.3%	0.0064	30%	100%	0.02
Light Liquid	57	0.0827	0.00013	0.3%	0.0215	30%	100%	0.07
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.31**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.54. Fugitive Emission for BOU

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	8	0.5789	0.0013	2.0%	0.1028	95%	100%	0.02
Light Liquid	0	0.1878	0.0037	2.0%	0.0000	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	2	0.0827	0.00013	0.3%	0.0008	30%	100%	0.00
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.02**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.55. Fugitive Emission for ISOM

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	55	0.5789	0.0013	2.0%	0.7069	95%	100%	0.15
Light Liquid	0	0.1878	0.0037	2.0%	0.0000	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	23	0.0827	0.00013	0.3%	0.0087	30%	100%	0.03
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	2	3.728	0.0985	2.0%	0.3422	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.18**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.56. Fugitive Emission for VRU300

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	-360	0.5789	0.0013	2.0%	-4.6267	95%	100%	-1.01
Light Liquid	-685	0.1878	0.0037	2.0%	-5.0567	95%	100%	-1.11
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	-12	0.963	0.0265	2.0%	-0.5428	80%	100%	-0.48
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	-720	0.0827	0.00013	0.3%	-0.2720	30%	100%	-0.83
Light Liquid	-1,370	0.0827	0.00013	0.3%	-0.5175	30%	100%	-1.59
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	-1	3.545	0.1971	2.0%	-0.2640	0%	100%	-1.16
Relief Valves	-18	3.728	0.0985	2.0%	-3.0796	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**-6.17**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.57. Fugitive Emission for DDU

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	25	0.5789	0.0013	2.0%	0.3213	95%	100%	0.07
Light Liquid	70	0.1878	0.0037	2.0%	0.5167	95%	100%	0.11
Heavy Liquid	8	0.00051	0.00051	2.0%	0.0041	30%	100%	0.01
Pumps								
Light Liquid	1	0.963	0.0265	2.0%	0.0452	80%	100%	0.04
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	15	0.0827	0.00013	0.3%	0.0057	30%	100%	0.02
Light Liquid	35	0.0827	0.00013	0.3%	0.0132	30%	100%	0.04
Heavy Liquid	4	0.0827	0.00013	0.3%	0.0015	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.30**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.58. Fugitive Emission for 1SPS

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	-194	0.5789	0.0013	2.0%	-2.4933	95%	100%	-0.55
Light Liquid	-10	0.1878	0.0037	2.0%	-0.0738	95%	100%	-0.02
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.963	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	-1	3.728	0.0985	2.0%	-0.1711	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**-0.56**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Table C.59. Fugitive Component Count and Emissions Summary

EPA Refinery Screening Fugitive Emission Factor Basis

Unit Name=>	4 Ultraformer		3 Ultraformer		12 Pipestill		DHT		New Coker		11B Coker		Gas Oil Hyrdotreater		Hydrogen	
Unit Code=>	4UF		3UF		12PS		DHT		FW Coker		11B Coker		GOHT		HU	
	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)
Valves																
Gas/Vapor	56	0.2	-887	-2.5	114	0.3	99	0.3	1,367	3.8	-1,094	-3.1	915	2.6	692	1.9
Light Liquid	13	0.0	-744	-1.2	197	0.3	51	0.1	1,367	2.2	-1,094	-1.8	912	1.5	219	0.4
Heavy Liquid	0	0.0	0	0.0	394	0.6	33	0.1	3,498	5.5	-2,798	-4.4	1,380	2.2	0	0.0
Pumps																
Light Liquid	0	0.0	-11	-0.4	3	0.1	1	0.0	16	0.6	-13	-0.5	8	0.3	6	0.2
Heavy Liquid	0	0.0	0	0.0	0	0.0	0	0.0	8	0.3	-6	-0.9	1	0.0	0	0.0
Flanges																
Gas/Vapor	113	0.1	-1,912	-2.2	456	0.5	105	0.1	2,196	2.5	-1,757	-2.0	3,660	4.2	2,768	3.2
Light Liquid	6	0.0	-2,828	-3.3	788	0.9	16	0.0	2,196	2.5	-1,757	-2.0	3,648	4.2	876	1.0
Heavy Liquid	0	0.0	0	0.0	1,576	1.8	24	0.0	5,802	6.7	-4,642	-5.4	7,475	8.7	0	0.0
Compressors	0	0.0	-1	-1.2	1	1.2	0	0.0	1	1.2	-1	-1.2	0	0.0	0	0.0
Relief Valves	1	0.0	-13	0.0	6	0.0	4	0.0	30	0.0	-24	0.0	26	0.0	15	0.0
Open-ended Lines	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Sampling Connection	0	0.0	-1	0.0	0	0.0	0	0.0	16	0.1	-13	-0.1	0	0.0	0	0.0
Totals:		**0.3**		**-10.8**		**5.8**		**0.6**		**25.6**		**-21.3**		**23.7**		**6.8**

Unit Name=>	OSBL		Sulfur Recovery		Sulfur Recovery		Sulfur Recovery		4TP		ARU		BOU		ISOM		VRU300		DDU	
Unit Code=>	OSBL		SRU		COT 1		COT 2		4TP		ARU		BOU		ISOM		VRU300		DDU	
	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)	Component Counts	VOC Emissions (tons/year)
Valves																				
Gas/Vapor	53	0.1	73	0.2	0	0.0	0	0.0	-5	0.0	26	0.1	8	0.0	55	0.2	-360	-1.0	25	0.1
Light Liquid	53	0.1	11	0.0	0	0.0	0	0.0	-59	-0.1	94	0.2	0	0.0	0	0.0	-685	-1.1	70	0.1
Heavy Liquid	26	0.0	22	0.0	0	0.0	0	0.0	-10	0.0	0	0.0	0	0.0	0	0.0	0	0.0	8	0.0
Pumps																				
Light Liquid	0	0.0	0	0.0	0	0.0	0	0.0	-1	0.0	0	0.0	0	0.0	0	0.0	-12	-0.5	1	0.0
Heavy Liquid	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Flanges																				
Gas/Vapor	212	0.2	292	0.3	0	0.0	0	0.0	0	0.0	17	0.0	2	0.0	23	0.0	-720	-0.8	15	0.0
Light Liquid	212	0.2	44	0.1	0	0.0	0	0.0	-20	0.0	57	0.1	0	0.0	0	0.0	-1,370	-1.6	35	0.0
Heavy Liquid	104	0.1	88	0.1	0	0.0	0	0.0	-40	0.0	0	0.0	0	0.0	0	0.0	0	0.0	4	0.0
Compressors	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	-1	-1.2	0	0.0
Relief Valves	0	0.0	2	0.0	0	0.0	0	0.0	-1	0.0	0	0.0	0	0.0	2	0.0	-18	0.0	0	0.0
Open-ended Lines	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Sampling Connection	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Totals:		**0.9**		**2.5**		**0.9**		**0.9**		**-0.2**		**0.3**		**0.0**		**0.2**		**-6.2**		**0.3**

OVERALL VOC TOTAL: 30.1 Tons/year

Table C.60. Fugitive Emission for Additional Existing Components in Heavy Liquid Service

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	Current LDAR Control Efficiency	Proposed LDAR Control Efficiency	Percent in VOC Service	Current VOC Emissions (Tons/yr)	Projected VOC Emissions (Tons/yr)	VOC Emission Reductions (Tons/yr)
Existing Pumps											
Heavy Liquid	269	0.8565	0.02976	2.0%	12.4533	30%	80%	100%	38.18	10.91	-27.27
								Total VOC Emissions (tons/yr):			**-27.27**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Table C.61. Project Marine Gasoline Loading Emissions

Gasoline Loaded		VOC			
		EF[2]	Unit	lb/hr[1]	tpy
4,000,000	bbl/yr	10	mg/L	1.6	7.0

Additional VRU emissions[2]

NOx (tpy)	CO (tpy)
5.6	2.2

[1] Hourly emission rate represents annual average hourly emissions.

[2] The Vapor Recovery Unit will control gasoline loading operations to 10 mg of VOC emissions per liter of product loaded. Vendor estimates include additional NOx and CO emissions.

Table C.62. 2003 Marine Loading Emissions

Gasoline Loaded			Vapor Pressure (psia)	MW	Temp (R)	VOC			
Product	Total	Unit				EF	Unit	lb/hr[1]	tpy
87R9+ REG	2,438,657	bbl/yr	5.016	65	530	3.832	lb/1000 gal	44.8	196.3
93R9+ PREM	161,495	bbl/yr	5.016	65	530	3.832	lb/1000 gal	3.0	13.0
							Total	**47.8**	**209.2**

AP-42 Section 5.2 Transportation and Marketing of Petroleum Liquids (01/95)

$$EF_{Load} = 12.46 * \frac{S * P * M}{T}$$

Where,

EF_{Load} = Loading Emission Factor (lb/1000 gal)

S = Saturation Factor (0.5 for submerged loading of a clean cargo tank)

P = True Vapor Pressure (psia)

M = Molecular Weight (lb/lbmol)

T = Temperature (R)

[1] Hourly emission rate represents annual average hourly emissions.

Table C.63. 2004 Marine Loading Emissions

Gasoline Loaded			Vapor Pressure (psia)	MW	Temp (R)	VOC			
Product	Total	Unit				EF	Unit	lb/hr[1]	tpy
ALKYLATE	42,146	bbl/yr	2.224	70	530	1.830	lb/1000 gal	0.4	1.6
HVN ULTRAFORMER FEED	95,007	bbl/yr	7.308	61	530	5.240	lb/1000 gal	2.4	10.5
93R9+ PREM	157,703	bbl/yr	5.016	65	530	3.832	lb/1000 gal	2.9	12.7
87R9+ REG	1,626,195	bbl/yr	5.016	65	530	3.832	lb/1000 gal	29.9	130.9
							Total	**35.5**	**155.6**

AP-42 Section 5.2 Transportation and Marketing of Petroleum Liquids (01/95)

$$EF_{Load} = 12.46 * \frac{S * P * M}{T}$$

Where,

EF_{Load} = Loading Emission Factor (lb/1000 gal)

S = Saturation Factor (0.5 for submerged loading of a clean cargo tank)

P = True Vapor Pressure (psia)

M = Molecular Weight (lb/lbmol)

T = Temperature (R)

[1] Hourly emission rate represents annual average hourly emissions.

Table C.64. Project Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	37.60	10^6 bbl/yr	103	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	14.2	62.0
FCU 600	24.09	10^6 bbl/yr	66	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	9.1	39.7

Process Unit	Usage[3,4]		$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
			EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	669,191	1000 lb coke burned/yr	0.465	lb/1000 lb coke burned	35.5	155.6	42	PPM @ 0% excess O_2	33.6	147.2	40	PPM @ 0% excess O_2	35.4	155.3	25	PPM @ 0% excess O_2	45.7	200.3	2.099	9.19	2.55E-04	lb/1000 lb coke burned	0.019	0.085	1.00E-06	lb/1000 lb coke burned	7.64E-05	3.35E-04	3.51E-06	lb/1000 lb coke burned	2.68E-04	1.17E-03
FCU 600	428,802	1000 lb coke burned/yr	0.350	lb/1000 lb coke burned	17.1	75.0	41	PPM @ 0% excess O_2	21.0	92.1	20	PPM @ 0% excess O_2	11.4	49.7	37	PPM @ 0% excess O_2	43.4	190.0	1.991	8.72	2.55E-04	lb/1000 lb coke burned	0.012	0.055	1.00E-06	lb/1000 lb coke burned	4.90E-05	2.14E-04	3.51E-06	lb/1000 lb coke burned	1.72E-04	7.53E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Future potential coke usage based on maximum annual average ratio of coke burned to fresh feed of 17.8 for FCU 500.
4. Future potential coke usage based on maximum annual average ratio of coke burned to fresh feed of 17.8 for FCU 600.
5. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must also be on a 0% O_2 basis.

Table C.65. 1999 Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	28.49	10^6 bbl/yr	78.1	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	10.7	47.0
FCU 600	21.71	10^6 bbl/yr	59.5	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	8.2	35.8

Process Unit	Usage		Excess Oxygen	$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
				EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	432,722	1000 lb coke burned/yr	1.90%	0.465	lb/1000 lb coke burned	23.0	100.6	26	PPM @ 1.9% excess O2	14.8	64.8	40	PPM @ 0% excess O_2	22.9	100.4	25	PPM @ 0% excess O_2	29.6	129.5	1.357	5.95	2.55E-04	lb/1000 lb coke burned	1.26E-02	5.52E-02	1.00E-06	lb/1000 lb coke burned	4.94E-05	2.16E-04	3.51E-06	lb/1000 lb coke burned	1.73E-04	7.59E-04
FCU 600	330,653	1000 lb coke burned/yr	1.4%	0.350	lb/1000 lb coke burned	13.2	57.9	22	PPM @ 1.4% excess O2	9.3	40.7	20	PPM @ 0% excess O_2	8.8	38.4	50	PPM @ 0% excess O_2	45.2	198.0	2.074	9.09	2.55E-04	lb/1000 lb coke burned	9.63E-03	4.22E-02	1.00E-06	lb/1000 lb coke burned	3.77E-05	1.65E-04	3.51E-06	lb/1000 lb coke burned	1.32E-04	5.80E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Baseline year NO_X and SO_2 concentrations have adjusted downward equal to the concentration limits from Consent Decree 4th Amendment.
4. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must on a 0% O_2 basis. For CO, the CO concentrations are corrected to 0% O_2 in the tpy calculation. For NO_X and SO_2, the ppm values do not need an additional correction to 0% O_2 since the consent decree limits, which are already on a 0% O@ basis, are used.

Table C.66. 2000 Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	30.80	10^6 bbl/yr	84.4	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	11.6	50.8
FCU 600	19.99	10^6 bbl/yr	54.8	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	7.5	33.0

Process Unit	Usage		Excess Oxygen	$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
				EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	469,214	1000 lb coke burned/yr	1.8%	0.465	lb/1000 lb coke burned	24.9	109.1	26	PPM @ 1.8% excess O2	16.0	69.9	40	PPM @ 0% excess O_2	24.9	108.9	25	PPM @ 0% excess O_2	32.1	140.5	1.472	6.45	2.55E-04	lb/1000 lb coke burned	1.37E-02	5.98E-02	1.00E-06	lb/1000 lb coke burned	5.36E-05	2.35E-04	3.51E-06	lb/1000 lb coke burned	1.88E-04	8.23E-04
FCU 600	330,454	1000 lb coke burned/yr	1.6%	0.350	lb/1000 lb coke burned	13.2	57.8	22	PPM @ 1.6% excess O2	9.4	41.2	20	PPM @ 0% excess O_2	8.8	38.3	50	PPM @ 0% excess O_2	45.2	197.8	2.073	9.08	2.55E-04	lb/1000 lb coke burned	9.62E-03	4.21E-02	1.00E-06	lb/1000 lb coke burned	3.77E-05	1.65E-04	3.51E-06	lb/1000 lb coke burned	1.32E-04	5.80E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Baseline year NO_X and SO_2 concentrations have adjusted downward equal to the concentration limits from Consent Decree 4th Amendment.
4. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must on a 0% O_2 basis. For CO, the CO concentrations are corrected to 0% O_2 in the tpy calculation. For NO_X and SO_2, the ppm values do not need an additional correction to 0% O_2 since the consent decree limits, which are already on a 0% O@ basis, are used.

Table C.67. 2001 Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	31.42	10^6 bbl/yr	86.1	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	11.8	51.8
FCU 600	19.96	10^6 bbl/yr	54.7	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	7.5	32.9

Process Unit	Usage		Excess Oxygen	$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
				EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	477,421	1000 lb coke burned/yr	2.3%	0.465	lb/1000 lb coke burned	25.3	111.0	26	PPM @ 2.3% excess O2	16.7	73.1	40	PPM @ 0% excess O_2	25.3	110.8	25	PPM @ 0% excess O_2	32.6	142.9	1.498	6.56	2.55E-04	lb/1000 lb coke burned	1.39E-02	6.09E-02	1.00E-06	lb/1000 lb coke burned	5.45E-05	2.39E-04	3.51E-06	lb/1000 lb coke burned	1.91E-04	8.38E-04
FCU 600	329,851	1000 lb coke burned/yr	1.7%	0.350	lb/1000 lb coke burned	13.2	57.7	22	PPM @ 1.7% excess O2	9.5	41.4	20	PPM @ 0% excess O_2	8.7	38.3	50	PPM @ 0% excess O_2	45.1	197.5	2.069	9.06	2.55E-04	lb/1000 lb coke burned	9.60E-03	4.21E-02	1.00E-06	lb/1000 lb coke burned	3.77E-05	1.65E-04	3.51E-06	lb/1000 lb coke burned	1.32E-04	5.79E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Baseline year NO_X and SO_2 concentrations have adjusted downward equal to the concentration limits from Consent Decree 4th Amendment.
4. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must on a 0% O_2 basis. For CO, the CO concentrations are corrected to 0% O_2 in the tpy calculation. For NO_X and SO_2, the ppm values do not need an additional correction to 0% O_2 since the consent decree limits, which are already on a 0% O@ basis, are used.

Table C.68. 2002 Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	34.77	10^6 bbl/yr	95.3	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	13.1	57.4
FCU 600	20.70	10^6 bbl/yr	56.7	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	7.8	34.1

Process Unit	Usage		Excess Oxygen	$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
				EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	530,789	1000 lb coke burned/yr	1.5%	0.465	lb/1000 lb coke burned	28.2	123.4	20	PPM @ 1.5% excess O2	13.7	59.9	40	PPM @ 0% excess O_2	28.1	123.1	25	PPM @ 0% excess O_2	36.3	158.9	1.665	7.29	2.55E-04	lb/1000 lb coke burned	1.55E-02	6.77E-02	1.00E-06	lb/1000 lb coke burned	6.06E-05	2.65E-04	3.51E-06	lb/1000 lb coke burned	2.13E-04	9.32E-04
FCU 600	313,311	1000 lb coke burned/yr	1.4%	0.350	lb/1000 lb coke burned	12.5	54.8	14	PPM @ 1.4% excess O2	5.6	24.6	20	PPM @ 0% excess O_2	8.3	36.3	50	PPM @ 0% excess O_2	42.8	187.6	1.966	8.61	2.55E-04	lb/1000 lb coke burned	9.12E-03	3.99E-02	1.00E-06	lb/1000 lb coke burned	3.58E-05	1.57E-04	3.51E-06	lb/1000 lb coke burned	1.26E-04	5.50E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Baseline year NO_X and SO_2 concentrations have adjusted downward equal to the concentration limits from Consent Decree 4th Amendment.
4. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must on a 0% O_2 basis. For CO, the CO concentrations are corrected to 0% O_2 in the tpy calculation. For NO_X and SO_2, the ppm values do not need an additional correction to 0% O_2 since the consent decree limits, which are already on a 0% O@ basis, are used.

Table C.69. 2003 Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	30.07	10^6 bbl/yr	82.4	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	11.3	49.6
FCU 600	17.64	10^6 bbl/yr	48.3	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	6.6	29.1

Process Unit	Usage		Excess Oxygen	$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
				EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	450,193	1000 lb coke burned/yr	2.0%	0.465	lb/1000 lb coke burned	23.9	104.7	24	PPM @ 2% excess O2	14.3	62.6	40	PPM @ 0% excess O_2	23.8	104.4	25	PPM @ 0% excess O_2	30.8	134.8	1.412	6.19	2.55E-04	lb/1000 lb coke burned	1.31E-02	5.74E-02	1.00E-06	lb/1000 lb coke burned	5.14E-05	2.25E-04	3.51E-06	lb/1000 lb coke burned	1.80E-04	7.90E-04
FCU 600	308,346	1000 lb coke burned/yr	1.4%	0.350	lb/1000 lb coke burned	12.3	54.0	19	PPM @ 1.4% excess O2	7.5	32.8	20	PPM @ 0% excess O_2	8.2	35.8	50	PPM @ 0% excess O_2	42.1	184.6	1.934	8.47	2.55E-04	lb/1000 lb coke burned	8.98E-03	3.93E-02	1.00E-06	lb/1000 lb coke burned	3.52E-05	1.54E-04	3.51E-06	lb/1000 lb coke burned	1.24E-04	5.41E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Baseline year NO_X and SO_2 concentrations have adjusted downward equal to the concentration limits from Consent Decree 4th Amendment.
4. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must on a 0% O_2 basis. For CO, the CO concentrations are corrected to 0% O_2 in the tpy calculation. For NO_X and SO_2, the ppm values do not need an additional correction to 0% O_2 since the consent decree limits, which are already on a 0% O@ basis, are used.

Table C.70. 2004 Fluidized Catalytic Cracking Emissions

Process Unit	Usage				VOC						
					EF	Unit	% Efficiency[1]	Resulting EF	Unit	lb/hr[2]	tpy
FCU 500	32.84	10^6 bbl/yr	90.0	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	12.4	54.2
FCU 600	19.77	10^6 bbl/yr	54.2	1000 bbl/day	220	lb/1000 bbl	98.5%	3.3	lb/1000 bbl	7.4	32.6

Process Unit	Usage		Excess Oxygen	$PM/PM_{10}/PM_{2.5}$				CO				NO_X				SO_2				H_2SO_4 Mist		Pb				Hg				Be			
				EF	Unit	lb/hr[2]	tpy	Conc.	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	Conc.[3]	Unit	lb/hr[2]	tpy	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy	EF	Unit	lb/hr[1]	tpy
FCU 500	494,967	1000 lb coke burned/yr	1.9%	0.465	lb/1000 lb coke burned	26.3	115.1	34	PPM @ 1.9% excess O2	22.2	97.1	40	PPM @ 0% excess O_2	26.2	114.8	25	PPM @ 0% excess O_2	33.8	148.2	1.553	6.80	2.55E-04	lb/1000 lb coke burned	1.44E-02	6.31E-02	1.00E-06	lb/1000 lb coke burned	5.65E-05	2.47E-04	3.51E-06	lb/1000 lb coke burned	1.98E-04	8.69E-04
FCU 600	377,852	1000 lb coke burned/yr	2.1%	0.350	lb/1000 lb coke burned	15.1	66.1	33	PPM @ 2.1% excess O2	16.6	72.6	20	PPM @ 0% excess O_2	10.0	43.8	50	PPM @ 0% excess O_2	51.6	226.2	2.370	10.38	2.55E-04	lb/1000 lb coke burned	1.10E-02	4.82E-02	1.00E-06	lb/1000 lb coke burned	4.31E-05	1.89E-04	3.51E-06	lb/1000 lb coke burned	1.51E-04	6.63E-04

1. The VOC percent efficiency of 98.5% is based a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion.
2. Hourly emission rate represents annual average hourly emissions.
3. Baseline year NO_X and SO_2 concentrations have adjusted downward equal to the concentration limits from Consent Decree 4th Amendment.
4. CO, NO_X, and SO_2 emissions are based on a stoichiometricly derived factor of 11.6 lbs flue gas generated per lb of coke burned. Note that this factor is on a 0% O_2 basis. Therefore, the ppm values used in the calculations for CO, NO_X, and SO_2 must on a 0% O_2 basis. For CO, the CO concentrations are corrected to 0% O_2 in the tpy calculation. For NO_X and SO_2, the ppm values do not need an additional correction to 0% O_2 since the consent decree limits, which are already on a 0% O@ basis, are used.

Table C.70a. Historical Reported and Allowable SO_2 Emissions for Fluidized Catalytic Cracking Unit 600

FCU 600 Emissions from Annual Emission Reports (As Reported)

Year	SO_2 (ton/yr)
1999	1,769.9
2000	2,031.9

FCU 600 Estimated SO_2 Allowable Emissions

Allowable Usage[1]				SO_2 Concentration[2]		SO_2 PTE tpy
80	1000 bbl/day	16.7	lb coke burned/ bbl fresh feed	50	PPM @ 0% excess O_2	291.4

Baseline Period	Emissions Reduction (tpy)	10% of Emissions Reduction[3] (tpy)
1999-2000	1,609.5	160.9

1. The FCU 600 Allowable Emissions were calculated using the maximum capacity of 80 (1000 bbl/day) and the ratio of coke burned to fresh feed, which is based on historical FCU 600 usage.
2. The Consent Decree limits FCU 600 to an SO_2 concentration of 50 ppm at 0% excess O_2.
3. Pursuant to the BP Whiting Consent Decree, up to ten percent (10%) of the SO_2 reduction credits generated by the FCU 600 SO_2 emissions reduction to 50 ppm could be used for netting SO_2 emissions increases that result from the construction or modification of "netting/offset generating units".

Table C.71. Existing Unit Volatile Organic Compound Emissions

Process Unit	Operating Rate					VOC						
	Future		Baseline Emissions (2001-2002)		Difference	Future		Baseline		Calculation Cells		tpy[1]
						EF	Unit	EF	Unit	Future	Baseline	
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	124.79	MMBtu/hr	49.11	0.0054	lb/MMBtu	0.0054	lb/MMBtu	4.1	2.9	1.2
H-2	32.3	MMBtu/hr	27.59	MMBtu/hr	4.71	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.8	0.7	0.1
H-3	49.2	MMBtu/hr	41.75	MMBtu/hr	7.45	0.0054	lb/MMBtu	0.0054	lb/MMBtu	1.16	0.99	0.2
11C PS												
H-200	182.8	MMBtu/hr	157.60	MMBtu/hr	25.20	0.0054	lb/MMBtu	0.0054	lb/MMBtu	4.3	3.7	0.6
H-300	72.0	MMBtu/hr	82.79	MMBtu/hr	-10.79	0.0054	lb/MMBtu	0.0054	lb/MMBtu	1.7	2.0	-0.3
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	38.66	MMBtu/hr	-9.06	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.7	0.9	-0.2
F-8A	142.3	MMBtu/hr	91.61	MMBtu/hr	50.69	0.0054	lb/MMBtu	0.0054	lb/MMBtu	3.4	2.2	1.2
F-8B	142.3	MMBtu/hr	88.62	MMBtu/hr	53.68	0.0054	lb/MMBtu	0.0054	lb/MMBtu	3.4	2.1	1.3
F-2	169.9	MMBtu/hr	206.97	MMBtu/hr	-37.07	0.0054	lb/MMBtu	0.0054	lb/MMBtu	4.0	4.9	-0.9
F-3	180.0	MMBtu/hr	177.52	MMBtu/hr	2.48	0.0054	lb/MMBtu	0.0054	lb/MMBtu	4.3	4.2	0.1
F-4	96.8	MMBtu/hr	112.22	MMBtu/hr	-15.42	0.0054	lb/MMBtu	0.0054	lb/MMBtu	2.3	2.7	-0.4
F-5	48.8	MMBtu/hr	58.38	MMBtu/hr	-9.58	0.0054	lb/MMBtu	0.0054	lb/MMBtu	1.2	1.4	-0.2
F-6	21.7	MMBtu/hr	28.71	MMBtu/hr	-7.01	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.5	0.7	-0.2
F-7	36.2	MMBtu/hr	35.21	MMBtu/hr	0.99	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.9	0.8	0.0
Regen[2]										1.7	1.2	0.5
Fugitives												0.3
ARU												
F-200A	144.4	MMBtu/hr	132.16	MMBtu/hr	12.24	0.0054	lb/MMBtu	0.0054	lb/MMBtu	3.4	3.1	0.3
F-200B	144.4	MMBtu/hr	140.99	MMBtu/hr	3.41	0.0054	lb/MMBtu	0.0054	lb/MMBtu	3.4	3.3	0.1
BOU												
F-401	23.0	MMBtu/hr	13.80	MMBtu/hr	9.20	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.5	0.3	0.2
CFHU												
F-801A	24.6	MMBtu/hr	16.59	MMBtu/hr	8.01	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.6	0.4	0.2
F-801B	24.6	MMBtu/hr	15.76	MMBtu/hr	8.84	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.6	0.4	0.2
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.60	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.6	0.0	0.6
CRU												
F-101	23.8	MMBtu/hr	28.80	MMBtu/hr	-5.00	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.6	0.7	-0.1
F-102	23.8	MMBtu/hr	15.00	MMBtu/hr	8.80	0.0054	lb/MMBtu	0.0054	lb/MMBtu	0.6	0.4	0.2
DDU												
WB-301	70.8	MMBtu/hr	26.35	MMBtu/hr	44.45	0.0054	lb/MMBtu	0.0054	lb/MMBtu	1.7	0.6	1.0
WB-302	55.8	MMBtu/hr	60.54	MMBtu/hr	-4.74	0.0054	lb/MMBtu	0.0054	lb/MMBtu	1.3	1.4	-0.1
ISOM												
H-1	153.2	MMBtu/hr	154.70	MMBtu/hr	-1.50	0.0054	lb/MMBtu	0.0054	lb/MMBtu	3.6	3.7	0.0
HU												
B-501	320.7	MMBtu/hr	167.81	MMBtu/hr	152.89	0.0054	lb/MMBtu	0.0054	lb/MMBtu	7.6	4.0	3.6
Fluidized Catalytic Cracking												
FCU 500	103	1000 bbl/day	90.7	1000 bbl/day	12.33	220	lb/1000 bbl	220	lb/1000 bbl	62.0	54.6	7.4
FCU 600	66	1000 bbl/day	55.7	1000 bbl/day	10.31	220	lb/1000 bbl	220	lb/1000 bbl	39.7	33.5	6.2

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

[2] 4UF Reformer Regen emissions based on data recorded by BP Whiting PI data collection system.

Table C.72. Existing Unit Nitrogen Oxide Emissions

Process Unit	Operating Rate					NOx						
	Future		Baseline Emissions (1999-2000)		Difference	Future		Baseline		Calculation Cells		tpy[1]
						EF	Unit	EF	Unit	Future	Baseline	
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	138.50	MMBtu/hr	35.40	0.166	lb/MMBtu	0.166	lb/MMBtu	126.4	100.7	25.7
H-2	32.3	MMBtu/hr	20.71	MMBtu/hr	11.59	0.098	lb/MMBtu	0.098	lb/MMBtu	13.9	8.9	5.0
H-3	49.2	MMBtu/hr	33.30	MMBtu/hr	15.90	0.098	lb/MMBtu	0.098	lb/MMBtu	21.1	14.3	6.8
11C PS												
H-200[2]	182.8	MMBtu/hr	92.67	MMBtu/hr	90.13	0.05	lb/MMBtu	0.275	lb/MMBtu	40.0	111.4	-71.4
H-300	72.0	MMBtu/hr	79.03	MMBtu/hr	-7.03	0.137	lb/MMBtu	0.137	lb/MMBtu	43.3	47.5	-4.2
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	37.97	MMBtu/hr	-8.37	0.098	lb/MMBtu	0.098	lb/MMBtu	12.7	16.3	-3.6
F-8A	142.3	MMBtu/hr	98.57	MMBtu/hr	43.73	0.275	lb/MMBtu	0.275	lb/MMBtu	171.1	118.5	52.6
F-8B	142.3	MMBtu/hr	92.86	MMBtu/hr	49.44	0.275	lb/MMBtu	0.275	lb/MMBtu	171.1	111.7	59.4
F-2	169.9	MMBtu/hr	225.75	MMBtu/hr	-55.85	0.186	lb/MMBtu	0.186	lb/MMBtu	138.6	184.2	-45.6
F-3	180.0	MMBtu/hr	201.41	MMBtu/hr	-21.41	0.275	lb/MMBtu	0.275	lb/MMBtu	216.4	242.2	-25.7
F-4	96.8	MMBtu/hr	121.15	MMBtu/hr	-24.35	0.275	lb/MMBtu	0.275	lb/MMBtu	116.4	145.7	-29.3
F-5	48.8	MMBtu/hr	44.02	MMBtu/hr	4.78	0.098	lb/MMBtu	0.098	lb/MMBtu	21.0	18.9	2.1
F-6	21.7	MMBtu/hr	40.13	MMBtu/hr	-18.43	0.098	lb/MMBtu	0.098	lb/MMBtu	9.3	17.2	-7.9
F-7	36.2	MMBtu/hr	31.56	MMBtu/hr	4.64	0.098	lb/MMBtu	0.098	lb/MMBtu	15.5	13.6	2.0
Regen												
ARU												
F-200A	144.4	MMBtu/hr	165.01	MMBtu/hr	-20.61	0.275	lb/MMBtu	0.275	lb/MMBtu	173.6	198.4	-24.8
F-200B	144.4	MMBtu/hr	170.06	MMBtu/hr	-25.66	0.275	lb/MMBtu	0.275	lb/MMBtu	173.6	204.5	-30.8
BOU												
F-401	23.0	MMBtu/hr	15.19	MMBtu/hr	7.81	0.098	lb/MMBtu	0.098	lb/MMBtu	9.9	6.5	3.4
CFHU												
F-801A	24.6	MMBtu/hr	11.22	MMBtu/hr	13.38	0.049	lb/MMBtu	0.049	lb/MMBtu	5.3	2.4	2.9
F-801B	24.6	MMBtu/hr	11.22	MMBtu/hr	13.38	0.049	lb/MMBtu	0.049	lb/MMBtu	5.3	2.4	2.9
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.60	0.036	lb/MMBtu	0.036	lb/MMBtu	3.9	0.0	3.9
CRU												
F-101	23.8	MMBtu/hr	43.87	MMBtu/hr	-20.07	0.080	lb/MMBtu	0.080	lb/MMBtu	8.3	15.4	-7.0
F-102	23.8	MMBtu/hr	22.17	MMBtu/hr	1.63	0.080	lb/MMBtu	0.080	lb/MMBtu	8.3	7.8	0.6
DDU												
WB-301	70.8	MMBtu/hr	37.98	MMBtu/hr	32.82	0.035	lb/MMBtu	0.035	lb/MMBtu	10.7	5.8	5.0
WB-302	55.8	MMBtu/hr	61.91	MMBtu/hr	-6.11	0.030	lb/MMBtu	0.030	lb/MMBtu	7.3	8.1	-0.8
ISOM												
H-1	153.2	MMBtu/hr	180.24	MMBtu/hr	-27.04	0.275	lb/MMBtu	0.275	lb/MMBtu	184.2	216.7	-32.5
HU												
B-501	320.7	MMBtu/hr	179.01	MMBtu/hr	141.69	0.068	lb/MMBtu	0.068	lb/MMBtu	94.8	52.9	41.9
Fluidized Catalytic Cracking												
FCU 500	103	1000 bbl/day	81.2	1000 bbl/day	21.8	40	PPM	40	PPM	155.3	104.6	50.6
	669,191	1000 lb coke burned/yr	450,968	1000 lb coke burned/yr	218,223							
FCU 600	66	1000 bbl/day	57.1	1000 bbl/day	8.9	20	PPM	20	PPM	49.7	38.3	11.4
	428,802	1000 lb coke burned/yr	330,554	1000 lb coke burned/yr	98,248							

1. Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.
2. As part of the CXHO project, BP Whiting will be installing Ultra-Low NOX burners on heater 11C PS H-200 to generate creditable emission reductions.

Table C.73. Existing Unit Sulfur Dioxide Emissions

Process Unit	Operating Rate					SO_2						
	Future		Baseline Emissions (2003-2004)		Difference	Future		Baseline		Calculation Cells		tpy[1]
						EF	Unit	EF	Unit	Future[2]	Baseline	
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	146.85	MMBtu/hr	27.1	0.0111	lb/MMBtu	0.0218	lb/MMBtu	8.4	14.0	-5.6
H-2	32.3	MMBtu/hr	21.34	MMBtu/hr	11.0	0.0111	lb/MMBtu	0.0218	lb/MMBtu	1.6	2.0	-0.5
H-3	49.2	MMBtu/hr	40.64	MMBtu/hr	8.6	0.0111	lb/MMBtu	0.0218	lb/MMBtu	2.4	3.9	-1.5
11C PS												
H-200	182.8	MMBtu/hr	99.13	MMBtu/hr	83.7	0.0111	lb/MMBtu	0.0218	lb/MMBtu	8.9	9.4	-0.6
H-300	72.0	MMBtu/hr	74.35	MMBtu/hr	-2.4	0.0111	lb/MMBtu	0.0218	lb/MMBtu	3.5	7.1	-3.6
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	36.17	MMBtu/hr	-6.6	0.0111	lb/MMBtu	0.0066	lb/MMBtu	1.4	1.0	0.4
F-8A	142.3	MMBtu/hr	70.64	MMBtu/hr	71.7	0.0111	lb/MMBtu	0.0066	lb/MMBtu	6.9	2.0	4.8
F-8B	142.3	MMBtu/hr	67.05	MMBtu/hr	75.3	0.0111	lb/MMBtu	0.0066	lb/MMBtu	6.9	1.9	4.9
F-2	169.9	MMBtu/hr	189.00	MMBtu/hr	-19.1	0.0111	lb/MMBtu	0.0066	lb/MMBtu	8.2	5.5	2.7
F-3	180.0	MMBtu/hr	164.04	MMBtu/hr	16.0	0.0111	lb/MMBtu	0.0066	lb/MMBtu	8.7	4.8	4.0
F-4	96.8	MMBtu/hr	90.74	MMBtu/hr	6.1	0.0111	lb/MMBtu	0.0066	lb/MMBtu	4.7	2.6	2.1
F-5	48.8	MMBtu/hr	47.35	MMBtu/hr	1.4	0.0111	lb/MMBtu	0.0066	lb/MMBtu	2.4	1.4	1.0
F-6	21.7	MMBtu/hr	32.40	MMBtu/hr	-10.7	0.0111	lb/MMBtu	0.0066	lb/MMBtu	1.1	0.9	0.1
F-7	36.2	MMBtu/hr	32.25	MMBtu/hr	4.0	0.0111	lb/MMBtu	0.0066	lb/MMBtu	1.8	0.9	0.8
Regen[3]										3.5	2.5	1.0
ARU												
F-200A	144.4	MMBtu/hr	170.57	MMBtu/hr	-26.2	0.0111	lb/MMBtu	0.0218	lb/MMBtu	7.0	16.3	-9.3
F-200B	144.4	MMBtu/hr	163.37	MMBtu/hr	-19.0	0.0111	lb/MMBtu	0.0218	lb/MMBtu	7.0	15.6	-8.6
BOU												
F-401	23.0	MMBtu/hr	11.29	MMBtu/hr	11.7	0.0111	lb/MMBtu	0.0066	lb/MMBtu	1.1	0.3	0.8
CFHU												
F-801A	24.6	MMBtu/hr	9.99	MMBtu/hr	14.6	0.0111	lb/MMBtu	0.0086	lb/MMBtu	1.2	0.4	0.8
F-801B	24.6	MMBtu/hr	10.17	MMBtu/hr	14.4	0.0111	lb/MMBtu	0.0086	lb/MMBtu	1.2	0.4	0.8
F-801C	24.6	MMBtu/hr	0.30	MMBtu/hr	24.3	0.0111	lb/MMBtu	0.0086	lb/MMBtu	1.2	0.0	1.2
CRU												
F-101	23.8	MMBtu/hr	20.98	MMBtu/hr	2.8	0.0111	lb/MMBtu	0.0065	lb/MMBtu	1.2	0.6	0.6
F-102	23.8	MMBtu/hr	21.51	MMBtu/hr	2.3	0.0111	lb/MMBtu	0.0065	lb/MMBtu	1.2	0.6	0.5
DDU												
WB-301	70.8	MMBtu/hr	36.40	MMBtu/hr	34.4	0.0111	lb/MMBtu	0.0218	lb/MMBtu	3.4	3.5	0.0
WB-302	55.8	MMBtu/hr	50.19	MMBtu/hr	5.6	0.0111	lb/MMBtu	0.0218	lb/MMBtu	2.7	4.8	-2.1
ISOM												
H-1	153.2	MMBtu/hr	135.21	MMBtu/hr	18.0	0.0111	lb/MMBtu	0.0218	lb/MMBtu	7.4	12.9	-5.5
HU												
B-501	320.7	MMBtu/hr	168.83	MMBtu/hr	151.9	0.0111	lb/MMBtu	0.0708	lb/MMBtu	15.5	52.3	-36.8
Fluidized Catalytic Cracking												
FCU 500	103	1000 bbl/day	86.2	1000 bbl/day	16.8	25	PPM	25	PPM	200.3	141.5	58.9
	669,191	1000 lb coke burned/yr	472,580	1000 lb coke burned/yr	196,611							
FCU 600	66	1000 bbl/day	51.2	1000 bbl/day	14.8	37	PPM	50	PPM	190.0	205.4	-15.4
	428,802	1000 lb coke burned/yr	343,099	1000 bbl/day	85,703							

1. Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.
2. Calculation accounts for annual average design refinery fuel gas higher heating value of 1,203 Btu/scf.
3. 4UF Reformer Regen emissions based on data recorded by BP Whiting PI data collection system.

Table C.74. Existing Unit PM (Filterable) Emissions

Process Unit	Operating Rate					PM						
			Baseline Emissions (2001-2002)			Future		Baseline		Calculation Cells		
	Future				Difference	EF	Unit	EF	Unit	Future	Baseline	tpy[1]
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	124.79	MMBtu/hr	49.11	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.4	1.0	0.4
H-2	32.3	MMBtu/hr	27.59	MMBtu/hr	4.71	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.3	0.2	0.0
H-3	49.2	MMBtu/hr	41.75	MMBtu/hr	7.45	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.4	0.3	0.1
11C PS												
H-200	182.8	MMBtu/hr	157.60	MMBtu/hr	25.20	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.5	1.3	0.2
H-300	72.0	MMBtu/hr	82.79	MMBtu/hr	-10.79	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.6	0.7	-0.1
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	38.66	MMBtu/hr	-9.06	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.3	-0.1
F-8A	142.3	MMBtu/hr	91.61	MMBtu/hr	50.69	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.2	0.7	0.4
F-8B	142.3	MMBtu/hr	88.62	MMBtu/hr	53.68	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.2	0.7	0.4
F-2	169.9	MMBtu/hr	206.97	MMBtu/hr	-37.07	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.4	1.7	-0.3
F-3	180.0	MMBtu/hr	177.52	MMBtu/hr	2.48	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.5	1.4	0.0
F-4	96.8	MMBtu/hr	112.22	MMBtu/hr	-15.42	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.8	0.9	-0.1
F-5	48.8	MMBtu/hr	58.38	MMBtu/hr	-9.58	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.4	0.5	-0.1
F-6	21.7	MMBtu/hr	28.71	MMBtu/hr	-7.01	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.2	-0.1
F-7	36.2	MMBtu/hr	35.21	MMBtu/hr	0.99	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.3	0.3	0.0
Regen												
ARU												
F-200A	144.4	MMBtu/hr	132.16	MMBtu/hr	12.24	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.2	1.1	0.1
F-200B	144.4	MMBtu/hr	140.99	MMBtu/hr	3.41	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.2	1.2	0.0
BOU												
F-401	23.0	MMBtu/hr	13.80	MMBtu/hr	9.20	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.1	0.1
CFHU												
F-801A	24.6	MMBtu/hr	16.59	MMBtu/hr	8.01	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.1	0.1
F-801B	24.6	MMBtu/hr	15.76	MMBtu/hr	8.84	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.1	0.1
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.60	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.0	0.2
CRU												
F-101	23.8	MMBtu/hr	28.80	MMBtu/hr	-5.00	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.2	0.0
F-102	23.8	MMBtu/hr	15.00	MMBtu/hr	8.80	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.2	0.1	0.1
DDU												
WB-301	70.8	MMBtu/hr	26.35	MMBtu/hr	44.45	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.6	0.2	0.4
WB-302	55.8	MMBtu/hr	60.54	MMBtu/hr	-4.74	0.0019	lb/MMBtu	0.0019	lb/MMBtu	0.5	0.5	0.0
ISOM												
H-1	153.2	MMBtu/hr	154.70	MMBtu/hr	-1.50	0.0019	lb/MMBtu	0.0019	lb/MMBtu	1.2	1.3	0.0
HU												
B-501	320.7	MMBtu/hr	167.81	MMBtu/hr	152.89	0.0019	lb/MMBtu	0.0019	lb/MMBtu	2.6	1.4	1.2
Fluidized Catalytic Cracking												
FCU 500	103	1000 bbl/day	90.7	1000 bbl/day	12.3	0.465	lb/1000 lb coke burned	0.465	lb/1000 lb coke burned	155.6	117.2	38.4
	669,191	1000 lb coke burned/yr	504,105	1000 lb coke burned/yr	165,086							
FCU 600	66	1000 bbl/day	55.7	1000 bbl/day	10.3	0.35	lb/1000 lb coke burned	0.35	lb/1000 lb coke burned	75.0	56.3	18.8
	428,802	1000 lb coke burned/yr	321,581	1000 lb coke burned/yr	107,221							

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

Table C.75. Existing Unit $PM_{10}/PM_{2.5}$ (Filterable + Condensable) Emissions

Process Unit	Operating Rate					$PM_{10}/PM_{2.5}$						
	Future		Baseline Emissions (2001-2002)		Difference	Future		Baseline[2]		Calculation Cells		tpy[1]
						EF	Unit	EF	Unit	Future	Baseline	
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	124.79	MMBtu/hr	49.11	0.0075	lb/MMBtu	0.0075	lb/MMBtu	5.7	4.1	1.6
H-2	32.3	MMBtu/hr	27.59	MMBtu/hr	4.71	0.0075	lb/MMBtu	0.0075	lb/MMBtu	1.1	0.9	0.2
H-3	49.2	MMBtu/hr	41.75	MMBtu/hr	7.45	0.0075	lb/MMBtu	0.0075	lb/MMBtu	1.6	1.4	0.2
11C PS												
H-200	182.8	MMBtu/hr	157.60	MMBtu/hr	25.20	0.0075	lb/MMBtu	0.0075	lb/MMBtu	6.0	5.1	0.8
H-300	72.0	MMBtu/hr	82.79	MMBtu/hr	-10.79	0.0075	lb/MMBtu	0.0075	lb/MMBtu	2.3	2.7	-0.4
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	38.66	MMBtu/hr	-9.06	0.0075	lb/MMBtu	0.004	lb/MMBtu	1.0	0.7	0.3
F-8A	142.3	MMBtu/hr	91.61	MMBtu/hr	50.69	0.0075	lb/MMBtu	0.004	lb/MMBtu	4.6	1.6	3.0
F-8B	142.3	MMBtu/hr	88.62	MMBtu/hr	53.68	0.0075	lb/MMBtu	0.004	lb/MMBtu	4.6	1.6	3.1
F-2	169.9	MMBtu/hr	206.97	MMBtu/hr	-37.07	0.0075	lb/MMBtu	0.004	lb/MMBtu	5.5	3.6	1.9
F-3	180.0	MMBtu/hr	177.52	MMBtu/hr	2.48	0.0075	lb/MMBtu	0.004	lb/MMBtu	5.9	3.1	2.8
F-4	96.8	MMBtu/hr	112.22	MMBtu/hr	-15.42	0.0075	lb/MMBtu	0.004	lb/MMBtu	3.2	2.0	1.2
F-5	48.8	MMBtu/hr	58.38	MMBtu/hr	-9.58	0.0075	lb/MMBtu	0.004	lb/MMBtu	1.6	1.0	0.6
F-6	21.7	MMBtu/hr	28.71	MMBtu/hr	-7.01	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.7	0.5	0.2
F-7	36.2	MMBtu/hr	35.21	MMBtu/hr	0.99	0.0075	lb/MMBtu	0.004	lb/MMBtu	1.2	0.6	0.6
Regen												
ARU												
F-200A	144.4	MMBtu/hr	132.16	MMBtu/hr	12.24	0.0075	lb/MMBtu	0.004	lb/MMBtu	4.7	2.3	2.4
F-200B	144.4	MMBtu/hr	140.99	MMBtu/hr	3.41	0.0075	lb/MMBtu	0.004	lb/MMBtu	4.7	2.5	2.2
BOU												
F-401	23.0	MMBtu/hr	13.80	MMBtu/hr	9.20	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.8	0.2	0.5
CFHU												
F-801A	24.6	MMBtu/hr	16.59	MMBtu/hr	8.01	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.8	0.3	0.5
F-801B	24.6	MMBtu/hr	15.76	MMBtu/hr	8.84	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.8	0.3	0.5
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.60	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.8	0.0	0.8
CRU												
F-101	23.8	MMBtu/hr	28.80	MMBtu/hr	-5.00	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.8	0.5	0.3
F-102	23.8	MMBtu/hr	15.00	MMBtu/hr	8.80	0.0075	lb/MMBtu	0.004	lb/MMBtu	0.8	0.3	0.5
DDU												
WB-301	70.8	MMBtu/hr	26.35	MMBtu/hr	44.45	0.0075	lb/MMBtu	0.004	lb/MMBtu	2.3	0.5	1.8
WB-302	55.8	MMBtu/hr	60.54	MMBtu/hr	-4.74	0.0075	lb/MMBtu	0.004	lb/MMBtu	1.8	1.1	0.8
ISOM												
H-1	153.2	MMBtu/hr	154.70	MMBtu/hr	-1.50	0.0075	lb/MMBtu	0.004	lb/MMBtu	5.0	2.7	2.3
HU												
B-501	320.7	MMBtu/hr	167.81	MMBtu/hr	152.89	0.0075	lb/MMBtu	0.0075	lb/MMBtu	10.5	5.5	5.0
Fluidized Catalytic Cracking												
FCU 500	103	1000 bbl/day	90.7	1000 bbl/day	12.3	0.465	lb/1000 lb coke burned	0.465	1000 lb coke burned/yr	155.6	117.2	38.4
	669,191	1000 lb coke burned/yr	504,105	1000 lb coke burned/yr	165,086							
FCU 600	66	1000 bbl/day	55.7	1000 bbl/day	10.3	0.35	lb/1000 lb coke burned	0.35	1000 lb coke burned/yr	75.0	56.3	18.8
	428,802	1000 lb coke burned/yr	321,581	1000 lb coke burned/yr	107,221							

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

[2] Based on interim guidance from US EPA, $PM_{2.5}$ is evaluated based on significant emission rate thresholds established for PM_{10}. The current PM_{10} SIP limits filterable PM_{10} emissions and compliance is based on reference test method 201A (which only quantifies filterable particulate matter). Although not required, BP Whiting has conservatively adjusted the PM10 baseline based on the PM_{10} SIP limits for PSD applicability purposes, which includes both filterable and condensable PM_{10}. $PM_{2.5}$ emissions are not regula by the Lake County PM10 SIP, however, to be conservative, BP Whiting has adjusted $PM_{2.5}$ baseline emissions in the same manner as for PM_{10} emissions.

Table C.76. Existing Unit Carbon Monoxide Emissions

Process Unit	Operating Rate					CO						
	Future		Baseline Emissions (1999-2000)		Difference	Future		Baseline		Calculation Cells		tpy[1]
						EF	Unit	EF	Unit	Future	Baseline	
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	138.50	MMBtu/hr	35.40	0.0824	lb/MMBtu	0.0824	lb/MMBtu	62.7	50.0	12.8
H-2	32.3	MMBtu/hr	20.71	MMBtu/hr	11.59	0.0824	lb/MMBtu	0.0824	lb/MMBtu	11.7	7.5	4.2
H-3	49.2	MMBtu/hr	33.30	MMBtu/hr	15.90	0.0824	lb/MMBtu	0.082	lb/MMBtu	17.7	12.0	5.7
11C PS												
H-200	182.8	MMBtu/hr	92.67	MMBtu/hr	90.13	0.0824	lb/MMBtu	0.082	lb/MMBtu	65.9	33.4	32.5
H-300	72.0	MMBtu/hr	79.03	MMBtu/hr	-7.03	0.0824	lb/MMBtu	0.082	lb/MMBtu	26.0	28.5	-2.5
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	37.97	MMBtu/hr	-8.37	0.0824	lb/MMBtu	0.082	lb/MMBtu	10.7	13.7	-3.0
F-8A	142.3	MMBtu/hr	98.57	MMBtu/hr	43.73	0.0824	lb/MMBtu	0.082	lb/MMBtu	51.3	35.6	15.8
F-8B	142.3	MMBtu/hr	92.86	MMBtu/hr	49.44	0.0824	lb/MMBtu	0.082	lb/MMBtu	51.3	33.0	18.3
F-2	169.9	MMBtu/hr	225.75	MMBtu/hr	-55.85	0.0824	lb/MMBtu	0.082	lb/MMBtu	61.3	81.4	-20.1
F-3	180.0	MMBtu/hr	201.41	MMBtu/hr	-21.41	0.0824	lb/MMBtu	0.082	lb/MMBtu	64.9	72.7	-7.7
F-4	96.8	MMBtu/hr	121.15	MMBtu/hr	-24.35	0.0824	lb/MMBtu	0.082	lb/MMBtu	34.9	43.7	-8.8
F-5	48.8	MMBtu/hr	44.02	MMBtu/hr	4.78	0.0824	lb/MMBtu	0.082	lb/MMBtu	17.6	15.9	1.7
F-6	21.7	MMBtu/hr	40.13	MMBtu/hr	-18.43	0.0824	lb/MMBtu	0.082	lb/MMBtu	7.8	14.5	-6.6
F-7	36.2	MMBtu/hr	31.56	MMBtu/hr	4.64	0.0824	lb/MMBtu	0.082	lb/MMBtu	13.1	11.4	1.7
Regen[2]										11.1	8.0	3.2
ARU												
F-200A	144.4	MMBtu/hr	165.01	MMBtu/hr	-20.61	0.0824	lb/MMBtu	0.082	lb/MMBtu	52.1	59.5	-7.4
F-200B	144.4	MMBtu/hr	170.06	MMBtu/hr	-25.66	0.0824	lb/MMBtu	0.082	lb/MMBtu	52.1	61.3	-9.3
BOU												
F-401	23.0	MMBtu/hr	15.19	MMBtu/hr	7.81	0.0824	lb/MMBtu	0.082	lb/MMBtu	8.3	5.5	2.8
CFHU												
F-801A	24.6	MMBtu/hr	11.22	MMBtu/hr	13.38	0.0824	lb/MMBtu	0.082	lb/MMBtu	8.9	4.0	4.8
F-801B	24.6	MMBtu/hr	11.22	MMBtu/hr	13.38	0.0824	lb/MMBtu	0.082	lb/MMBtu	8.9	4.0	4.8
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.60	0.0001	lb/MMBtu	0.0001	lb/MMBtu	0.0	0.0	0.0
CRU												
F-101	23.8	MMBtu/hr	43.87	MMBtu/hr	-20.07	0.0824	lb/MMBtu	0.0824	lb/MMBtu	8.6	15.8	-7.2
F-102	23.8	MMBtu/hr	22.17	MMBtu/hr	1.63	0.0824	lb/MMBtu	0.0824	lb/MMBtu	8.6	8.0	0.6
DDU												
WB-301	70.8	MMBtu/hr	37.98	MMBtu/hr	32.82	0.0400	lb/MMBtu	0.04	lb/MMBtu	12.4	6.7	5.7
WB-302	55.8	MMBtu/hr	61.91	MMBtu/hr	-6.11	0.0400	lb/MMBtu	0.04	lb/MMBtu	9.8	10.8	-1.1
ISOM												
H-1	153.2	MMBtu/hr	180.24	MMBtu/hr	-27.04	0.0824	lb/MMBtu	0.082	lb/MMBtu	55.3	65.0	-9.8
HU												
B-501	320.7	MMBtu/hr	179.01	MMBtu/hr	141.69	0.02	lb/MMBtu	0.02	lb/MMBtu	28.1	15.7	12.4
Fluidized Catalytic Cracking												
FCU 500	103	1000 bbl/day	81.2	1000 bbl/day	21.8	42	PPM	26	PPM	147.2	67.4	79.9
	669,191	1000 lb coke burned/yr	450,968	1000 lb coke burned/yr	218,223							
FCU 600	66	1000 bbl/day	57.1	1000 bbl/day	8.9	41	PPM	22	PPM	92.1	41.0	51.1
	428,802	1000 lb coke burned/yr	330,554	1000 lb coke burned/yr	98,248							

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

[2] 4UF Reformer Regen emissions based on data recorded by BP Whiting PI data collection system.

Table C.77. Existing Unit Sulfuric Acid Mist Emissions

Process Unit	SO_2 Emissions					H_2SO_4 Mist		
	Future		Baseline Emissions (2003-2004)		Difference	Calculation Cells		tpy[1]
						Future	Baseline	
Crude and Coking								
11A PS								
H-1X	8.4	tpy	14.0	tpy	-5.57	0.39	0.64	-0.26
H-2	1.6	tpy	2.0	tpy	-0.47	0.07	0.09	-0.02
H-3	2.4	tpy	3.9	tpy	-1.49	0.11	0.18	-0.07
11C PS								
H-200	8.9	tpy	9.4	tpy	-0.59	0.41	0.43	-0.03
H-300	3.5	tpy	7.1	tpy	-3.60	0.16	0.33	-0.17
Hydroprocessing								
4UF								
F-1	1.4	tpy	1.0	tpy	0.39	0.07	0.05	0.02
F-8A	6.9	tpy	2.0	tpy	4.84	0.32	0.09	0.22
F-8B	6.9	tpy	1.9	tpy	4.95	0.32	0.09	0.23
F-2	8.2	tpy	5.5	tpy	2.75	0.38	0.25	0.13
F-3	8.7	tpy	4.8	tpy	3.96	0.40	0.22	0.18
F-4	4.7	tpy	2.6	tpy	2.06	0.22	0.12	0.09
F-5	2.4	tpy	1.4	tpy	0.99	0.11	0.06	0.05
F-6	1.1	tpy	0.9	tpy	0.11	0.05	0.04	0.01
F-7	1.8	tpy	0.9	tpy	0.82	0.08	0.04	0.04
Regen[2]	3.5	tpy	2.5	tpy	0.98	0.16	0.11	0.05
ARU								
F-200A	7.0	tpy	16.3	tpy	-9.26	0.32	0.75	-0.42
F-200B	7.0	tpy	15.6	tpy	-8.57	0.32	0.71	-0.39
BOU								
F-401	1.1	tpy	0.3	tpy	0.79	0.05	0.02	0.04
CFHU								
F-801A	1.2	tpy	0.4	tpy	0.82	0.05	0.02	0.04
F-801B	1.2	tpy	0.4	tpy	0.81	0.05	0.02	0.04
F-801C	1.2	tpy	0.0	tpy	1.18	0.05	0.00	0.05
CRU								
F-101	1.2	tpy	0.6	tpy	0.56	0.05	0.03	0.03
F-102	1.2	tpy	0.6	tpy	0.54	0.05	0.03	0.02
DDU								
WB-301	3.4	tpy	3.5	tpy	-0.04	0.16	0.16	0.00
WB-302	2.7	tpy	4.8	tpy	-2.08	0.12	0.22	-0.10
ISOM								
H-1	7.4	tpy	12.9	tpy	-5.46	0.34	0.59	-0.25
HU								
B-501	15.5	tpy	52.3	tpy	-36.79	0.71	2.40	-1.69
FCU								
FCU 500	200.3	tpy	141.5	tpy	58.86	9.19	6.49	2.70
FCU 600	190.0	tpy	205.4	tpy	-15.44	8.72	9.43	-0.71

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

[2] 4UF Reformer Regen emissions based on data recorded by BP Whiting PI data collection system.

Table C.78. Existing Unit Lead Emissions

Process Unit	Operating Rate					Pb						
	Future		Baseline Emissions (2001-2002)		Difference	Future		Baseline		Calculation Cells		tpy[1]
						EF	Unit	EF	Unit	Future	Baseline	
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	124.79	MMBtu/hr	49.1	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.7E-04	2.7E-04	1.1E-04
H-2	32.3	MMBtu/hr	27.59	MMBtu/hr	4.7	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	6.9E-05	5.9E-05	1.0E-05
H-3	49.2	MMBtu/hr	41.75	MMBtu/hr	7.5	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	1.1E-04	9.0E-05	1.6E-05
11C PS												
H-200	182.8	MMBtu/hr	157.60	MMBtu/hr	25.2	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.9E-04	3.4E-04	5.2E-05
H-300	72.0	MMBtu/hr	82.79	MMBtu/hr	-10.8	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	1.5E-04	1.8E-04	-2.3E-05
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	38.66	MMBtu/hr	-9.1	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	6.4E-05	8.3E-05	-1.9E-05
F-8A	142.3	MMBtu/hr	91.61	MMBtu/hr	50.7	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.1E-04	2.0E-04	1.1E-04
F-8B	142.3	MMBtu/hr	88.62	MMBtu/hr	53.7	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.1E-04	1.9E-04	1.2E-04
F-2	169.9	MMBtu/hr	206.97	MMBtu/hr	-37.1	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.6E-04	4.4E-04	-8.0E-05
F-3	180.0	MMBtu/hr	177.52	MMBtu/hr	2.5	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.9E-04	3.8E-04	5.3E-06
F-4	96.8	MMBtu/hr	112.22	MMBtu/hr	-15.4	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	2.1E-04	2.4E-04	-3.3E-05
F-5	48.8	MMBtu/hr	58.38	MMBtu/hr	-9.6	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	1.0E-04	1.3E-04	-2.1E-05
F-6	21.7	MMBtu/hr	28.71	MMBtu/hr	-7.0	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	4.7E-05	6.2E-05	-1.5E-05
F-7	36.2	MMBtu/hr	35.21	MMBtu/hr	1.0	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	7.8E-05	7.6E-05	2.1E-06
Regen												
ARU												
F-200A	144.4	MMBtu/hr	132.16	MMBtu/hr	12.2	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.1E-04	2.8E-04	2.6E-05
F-200B	144.4	MMBtu/hr	140.99	MMBtu/hr	3.4	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.1E-04	3.0E-04	7.3E-06
BOU												
F-401	23.0	MMBtu/hr	13.80	MMBtu/hr	9.2	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	4.9E-05	3.0E-05	2.0E-05
CFHU												
F-801A	24.6	MMBtu/hr	16.59	MMBtu/hr	8.0	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	5.3E-05	3.6E-05	1.7E-05
F-801B	24.6	MMBtu/hr	15.76	MMBtu/hr	8.8	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	5.3E-05	3.4E-05	1.9E-05
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.6	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	5.3E-05	0.0E+00	5.3E-05
CRU												
F-101	23.8	MMBtu/hr	28.80	MMBtu/hr	-5.0	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	5.1E-05	6.2E-05	-1.1E-05
F-102	23.8	MMBtu/hr	15.00	MMBtu/hr	8.8	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	5.1E-05	3.2E-05	1.9E-05
DDU												
WB-301	70.8	MMBtu/hr	26.35	MMBtu/hr	44.4	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	1.5E-04	5.7E-05	9.5E-05
WB-302	55.8	MMBtu/hr	60.54	MMBtu/hr	-4.7	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	1.2E-04	1.3E-04	-1.0E-05
ISOM												
H-1	153.2	MMBtu/hr	154.70	MMBtu/hr	-1.5	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	3.3E-04	3.3E-04	-3.2E-06
HU												
B-501	320.7	MMBtu/hr	167.81	MMBtu/hr	152.9	4.90E-07	lb/MMBtu	4.90E-07	lb/MMBtu	6.9E-04	3.6E-04	3.3E-04
FCU 500	103	1000 bbl/day	81.2	1000 bbl/day	21.8	0.000255	lb/1000 lb Coke Burn	0.000255	lb/1000 lb Coke Burn	8.53E-02	6.43E-02	2.10E-02
	669,191	1000 lb coke burned/yr	504,105	1000 lb coke burned/yr	165,086							
FCU 600	66	1000 bbl/day	57.1	1000 bbl/day	8.9	0.000255	lb/1000 lb Coke Burn	0.000255	lb/1000 lb Coke Burn	5.47E-02	4.10E-02	1.37E-02
	428,802	1000 lb coke burned/yr	321,581	1000 lb coke burned/yr	107,221							

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

Table C.79. Existing Unit Mercury Emissions

Process Unit	Operating Rate					Hg						
	Future		Baseline Emissions (2001-2002)		Difference	Future		Baseline		Calculation Cells		tpy[1]
						EF	Unit	EF	Unit	Future	Baseline	
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	124.79	MMBtu/hr	49.1	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.4E-04	9.8E-05	3.9E-05
H-2	32.3	MMBtu/hr	27.59	MMBtu/hr	4.7	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	2.5E-05	2.2E-05	3.7E-06
H-3	49.2	MMBtu/hr	41.75	MMBtu/hr	7.5	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	3.9E-05	3.3E-05	5.9E-06
11C PS												
H-200	182.8	MMBtu/hr	157.60	MMBtu/hr	25.2	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.4E-04	1.2E-04	1.6E-05
H-300	72.0	MMBtu/hr	82.79	MMBtu/hr	-10.8	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	5.7E-05	6.5E-05	-8.5E-06
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	38.66	MMBtu/hr	-9.1	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	2.3E-05	3.0E-05	-7.1E-06
F-8A	142.3	MMBtu/hr	91.61	MMBtu/hr	50.7	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.1E-04	7.2E-05	4.0E-05
F-8B	142.3	MMBtu/hr	88.62	MMBtu/hr	53.7	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.1E-04	7.0E-05	4.2E-05
F-2	169.9	MMBtu/hr	206.97	MMBtu/hr	-37.1	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.3E-04	1.6E-04	-2.9E-05
F-3	180.0	MMBtu/hr	177.52	MMBtu/hr	2.5	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.4E-04	1.4E-04	2.0E-06
F-4	96.8	MMBtu/hr	112.22	MMBtu/hr	-15.4	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	7.6E-05	8.8E-05	-1.2E-05
F-5	48.8	MMBtu/hr	58.38	MMBtu/hr	-9.6	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	3.8E-05	4.6E-05	-7.6E-06
F-6	21.7	MMBtu/hr	28.71	MMBtu/hr	-7.0	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.7E-05	2.3E-05	-5.5E-06
F-7	36.2	MMBtu/hr	35.21	MMBtu/hr	1.0	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	2.9E-05	2.8E-05	7.8E-07
Regen												
ARU												
F-200A	144.4	MMBtu/hr	132.16	MMBtu/hr	12.2	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.1E-04	1.0E-04	9.7E-06
F-200B	144.4	MMBtu/hr	140.99	MMBtu/hr	3.4	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.1E-04	1.1E-04	2.7E-06
BOU												
F-401	23.0	MMBtu/hr	13.80	MMBtu/hr	9.2	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.8E-05	1.1E-05	7.3E-06
CFHU												
F-801A	24.6	MMBtu/hr	16.59	MMBtu/hr	8.0	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.9E-05	1.3E-05	6.3E-06
F-801B	24.6	MMBtu/hr	15.76	MMBtu/hr	8.8	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.9E-05	1.2E-05	7.0E-06
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.6	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.9E-05	0.0E+00	1.9E-05
CRU												
F-101	23.8	MMBtu/hr	28.80	MMBtu/hr	-5.0	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.9E-05	2.3E-05	-3.9E-06
F-102	23.8	MMBtu/hr	15.00	MMBtu/hr	8.8	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.9E-05	1.2E-05	6.9E-06
DDU												
WB-301	70.8	MMBtu/hr	26.35	MMBtu/hr	44.4	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	5.6E-05	2.1E-05	3.5E-05
WB-302	55.8	MMBtu/hr	60.54	MMBtu/hr	-4.7	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	4.4E-05	4.8E-05	-3.7E-06
ISOM												
H-1	153.2	MMBtu/hr	154.70	MMBtu/hr	-1.5	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	1.2E-04	1.2E-04	-1.2E-06
HU												
B-501	320.7	MMBtu/hr	167.81	MMBtu/hr	152.9	1.80E-07	lb/MMBtu	1.80E-07	lb/MMBtu	2.5E-04	1.3E-04	1.2E-04
FCU 500	103	1000 bbl/day	90.7	1000 bbl/day	12.3	1.00E-06	lb/1000 lb Coke Burn	1.00E-06	lb/1000 lb Coke Burn	3.35E-04	2.52E-04	8.25E-05
	669,191	1000 lb coke burned/yr	504,105	1000 lb coke burned/yr	165,086							
FCU 600	66	1000 bbl/day	55.7	1000 bbl/day	10.3	1.00E-06	lb/1000 lb Coke Burn	1.00E-06	lb/1000 lb Coke Burn	2.14E-04	1.61E-04	5.36E-05
	428,802	1000 lb coke burned/yr	321,581	1000 lb coke burned/yr	107,221							

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

Table C.80. Existing Unit Beryllium Emissions

Process Unit	Operating Rate					Be						
	Future		Baseline Emissions (2001-2002)		Difference	Future		Baseline		Calculation Cells		tpy[1]
						EF	Unit	EF	Unit	Future	Baseline	
Crude and Coking												
11A PS												
H-1X	173.9	MMBtu/hr	124.79	MMBtu/hr	49.1	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	9.0E-06	6.4E-06	2.5E-06
H-2	32.3	MMBtu/hr	27.59	MMBtu/hr	4.7	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.7E-06	1.4E-06	2.4E-07
H-3	49.2	MMBtu/hr	41.75	MMBtu/hr	7.5	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	2.5E-06	2.2E-06	3.8E-07
11C PS												
H-200	182.8	MMBtu/hr	157.60	MMBtu/hr	25.2	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.0E-05	8.1E-06	1.9E-06
H-300	72.0	MMBtu/hr	82.79	MMBtu/hr	-10.8	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	3.7E-06	4.3E-06	-5.6E-07
Hydroprocessing												
4UF												
F-1	29.6	MMBtu/hr	38.66	MMBtu/hr	-9.1	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.5E-06	2.0E-06	-4.7E-07
F-8A	142.3	MMBtu/hr	91.61	MMBtu/hr	50.7	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	7.3E-06	4.7E-06	2.6E-06
F-8B	142.3	MMBtu/hr	88.62	MMBtu/hr	53.7	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	7.3E-06	4.6E-06	2.8E-06
F-2	169.9	MMBtu/hr	206.97	MMBtu/hr	-37.1	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	8.8E-06	1.1E-05	-1.9E-06
F-3	180.0	MMBtu/hr	177.52	MMBtu/hr	2.5	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	9.3E-06	9.1E-06	1.3E-07
F-4	96.8	MMBtu/hr	112.22	MMBtu/hr	-15.4	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	5.0E-06	5.8E-06	-7.9E-07
F-5	48.8	MMBtu/hr	58.38	MMBtu/hr	-9.6	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	2.5E-06	3.0E-06	-4.9E-07
F-6	21.7	MMBtu/hr	28.71	MMBtu/hr	-7.0	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.1E-06	1.5E-06	-3.6E-07
F-7	36.2	MMBtu/hr	35.21	MMBtu/hr	1.0	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.9E-06	1.8E-06	5.1E-08
Regen												
ARU												
F-200A	144.4	MMBtu/hr	132.16	MMBtu/hr	12.2	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	7.4E-06	6.8E-06	6.3E-07
F-200B	144.4	MMBtu/hr	140.99	MMBtu/hr	3.4	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	7.4E-06	7.3E-06	1.8E-07
BOU												
F-401	23.0	MMBtu/hr	13.80	MMBtu/hr	9.2	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.2E-06	7.1E-07	4.7E-07
CFHU												
F-801A	24.6	MMBtu/hr	16.59	MMBtu/hr	8.0	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.3E-06	8.6E-07	4.1E-07
F-801B	24.6	MMBtu/hr	15.76	MMBtu/hr	8.8	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.3E-06	8.1E-07	4.6E-07
F-801C	24.6	MMBtu/hr	0.00	MMBtu/hr	24.6	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.3E-06	0.0E+00	1.3E-06
CRU												
F-101	23.8	MMBtu/hr	28.80	MMBtu/hr	-5.0	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.2E-06	1.5E-06	-2.6E-07
F-102	23.8	MMBtu/hr	15.00	MMBtu/hr	8.8	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.2E-06	7.7E-07	4.5E-07
DDU												
WB-301	70.8	MMBtu/hr	26.35	MMBtu/hr	44.4	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	3.6E-06	1.4E-06	2.3E-06
WB-302	55.8	MMBtu/hr	60.54	MMBtu/hr	-4.7	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	2.9E-06	3.1E-06	-2.4E-07
ISOM												
H-1	153.2	MMBtu/hr	154.70	MMBtu/hr	-1.5	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	7.9E-06	8.0E-06	-7.7E-08
HU												
B-501	320.7	MMBtu/hr	167.81	MMBtu/hr	152.9	1.18E-08	lb/MMBtu	1.18E-08	lb/MMBtu	1.7E-05	8.6E-06	7.9E-06
FCU 500	103	1000 bbl/day	90.7	1000 bbl/day	12.3	3.51E-06	lb/1000 lb Coke Burn	3.51E-06	lb/1000 lb Coke Burn	1.17E-03	8.85E-04	2.90E-04
	669,191	1000 lb coke burned/yr	504,105	1000 lb coke burned/yr	165,086							
FCU 600	66	1000 bbl/day	55.7	1000 bbl/day	10.3	3.51E-06	lb/1000 lb Coke Burn	3.51E-06	lb/1000 lb Coke Burn	7.53E-04	5.64E-04	1.88E-04
	428,802	1000 lb coke burned/yr	321,581	1000 lb coke burned/yr	107,221							

[1] Emission decreases represent creditable emissions decreases when the future potential emissions are less than the baseline emissions.

Table C.81. Summary of Emissions from New Emission Units

Process Unit	VOC (ton/yr)	NO_x (ton/yr)	SO_2 (ton/yr)	PM (Filterable) (ton/yr)	PM_{10} (Filterable + Condensable) (ton/yr)	CO (ton/yr)	Sulfuric Acid Mist (ton/yr)	Lead (ton/yr)	Mercury (ton/yr)	Beryllium (ton/yr)	H_2S (tons/yr)	Total Reduced Sulfur (ton/yr)
Heaters												
DHT[1]												
B-601A - Duty - 42 MMBtu/hr	1.0	7.3	0.1	0.3	1.4	7.3	0.00	9.0E-05	3.3E-05	2.2E-06		
GOHT[2]												
F-901A - Duty 47 - MMBtu/hr	1.1	8.2	2.3	0.4	1.5	4.1	0.10	1.0E-04	3.7E-05	2.4E-06		
F-901B - Duty 47 - MMBtu/hr	1.1	8.2	2.3	0.4	1.5	4.1	0.10	1.0E-04	3.7E-05	2.4E-06		
12 PS[3]												
H-101A - Duty 355 MMBtu/hr	8.4	77.7	17.2	2.9	11.6	29.5	0.79	7.6E-04	2.8E-04	1.8E-05		
H-102 - Duty 331 MMBtu/hr	7.8	72.5	16.0	2.7	10.8	27.5	0.74	7.1E-04	2.6E-04	1.7E-05		
H-101B - Duty 355 MMBtu/hr	8.4	77.7	17.2	2.9	11.6	29.5	0.79	7.6E-04	2.8E-04	1.8E-05		
Coker[4] (#2 Coker)												
Heater H-201 - Duty 208 MMBtu/hr	4.9	18.2	10.1	2.3	7.4	17.3	0.46	4.5E-04	1.6E-04	1.1E-05		
Heater H-202 - Duty 208 MMBtu/hr	4.9	18.2	10.1	2.3	7.4	17.3	0.46	4.5E-04	1.6E-04	1.1E-05		
Heater H-203 - Duty 208 MMBtu/hr	4.9	18.2	10.1	2.3	7.4	17.3	0.46	4.5E-04	1.6E-04	1.1E-05		
Cooling Towers[5]												
New Cooling Tower 7	3.9			0.5	0.5							
New Cooling Tower 8	17.1			2.2	2.2							
New HU Cooling Tower	-			1.8	1.8							
SRU[6]												
New Claus Train D												
New Claus Train E												
Claus Offgas Treaters 1 and 2*	3.4	50.5	194.8	1.2	4.7	55.0	8.94	3.1E-04	1.1E-04	7.4E-06	14.3	14.3
Flares[7]												
GOHT Flare												
Pilot Emissions	0.0	0.2	0.00	0.00	0.01	0.2	0.00	9.2E-07	3.4E-07	2.2E-08		
Purge Emissions	2.1	1.0	0.2	0.0	0.1	5.5	0.01	7.3E-06	2.7E-06	2.7E-06		
South Flare												
Pilot Emissions	0.01	0.2	0.00	0.00	0.01	0.2	0.00	9.2E-07	3.4E-07	2.2E-08		
Purge Emissions	2.4	1.2	0.2	0.0	0.1	6.4	0.01	8.5E-06	8.5E-06	8.5E-06		
HU Flare												
Pilot Emissions	0.01	0.1	0.00	0.00	0.01	0.1	0.00	5.6E-07	2.1E-07	1.3E-08		
Fugitives from new and modified units												
DHT	0.6											
GOHT	23.7											
12 PS	5.8											
Coker	25.6											
SRU	4.2											
OSBL	0.9											
ARU	0.3											
BOU	0.0											
ISOM	0.2											
DDU	0.3											
OCC Sewer Changes	31.5											
Emissions Associated with Third Parties												
Hydrogen Plant[8] (3rd Party SMR)												
HU-1 - Duty 920 MMBtu/hr	13.7	52.4	0.6	27.4	27.4	60.4	0.0	4.9E-04	1.8E-04	1.2E-05		
HU-2 - Duty 920 MMBtu/hr	13.7	52.4	0.6	27.4	27.4	60.4	0.0	4.9E-04	1.8E-04	1.2E-05		
HU Fugitive Emissions	6.8					25.0						
New Storage Tanks[9]												
TK-6255 - Coker Feed Tank	0.06											
TK-SH-1and TK-SH-2 - Sulfur Bulk Storage Tanks Vented to Caustic Scrubber[10]											0.5	0.5
TK-5052 - Stormwater/Equalization Tank	0.01											
Brine Treatment System Tanks												
(TK-105A) Off spec tank 1[11]	0.72											
(TK-105B) Off spec tank 2[11]	0.72											
(TK-101) Separation tank 1[11]	0.43											
(TK-102) Separation tank 2[11]	0.43											
(TK-103) Separation tank 3[11]	0.43											
(TK-104A) Sludge holding tank 1[11]	0.44											
(TK-104B) Sludge holding tank 2[11]	0.44											
Fugitives dust from new coke handling				1.4	0.7				1.42E-06			
Particulate Emissions from Concrete Crushing				0.1	0.0							
Potential Emissions Increase from New Units	**202.47**	**464.35**	**281.67**	**78.77**	**125.80**	**367.36**	**12.93**	**5.18E-03**	**1.91E-03**	**1.35E-04**	**14.8**	**14.8**

[1] New DHT heater B-601A controlled by ultra-low NOx burners. Note this heater is replacing the existing DHT heater.
[2] New GOHT heaters F-901A and F-901B controlled by ultra-low NOx burners.
[3] 12PS H-2, H-1B, H-1AS, H-1AN, H-1CX and H-1CN are not being replaced with like-for-like replacement heaters. Therefore, the new heaters are considered new
[4] New Coker (#2 Coker) heaters H-201, H-202, and H-203 are controlled by low NOx burners and SCRs.
[5] New Cooling Towers based on 0.001% Liquid Drift Factor achieved with high efficiency drift eliminators.
[6] The two new SRU Claus trains have no direct emissions and are vented through new Claus Offgas Treaters (COTs).
[7] Flare emissions based on normal operation (i.e., purge gas flow rate).
[8] Hydrogen plant (3rd Party SMR) heaters HU-1 and HU-2 are controlled by low NOx burners and SCRs.
Additional CO fugitive emissions are included to account for general process fugitive emissions.
[9] All tanks emissions except for Tanks SH-1 and SH-2 were calculated using U.S. EPA's TANKS 4.0 Program.
[10] Total reduced sulfur (TRS) emissions from Tanks SH-1 and SH-2 were estimated based on anticipated TRS concentration after caustic scrubber.
[11] Tanks are controlled to 95% reduction in VOC emissions.
* Note SO_2 emissions from the COT 1 and COT 2 include future sulfur loading emissions.

Table C.82. Project Net Emission Increases

Project Emissions Baseline 24-Month Period[1]	2001-2002	1999-2000	2001-2002	2001-2002	1999-2000	2003-2004	2001-2002	2001-2002	2001-2002	2000-2001	2000-2001
Pollutant	**VOC (ton/yr)**	**NOx (ton/yr)**	**PM (Filterable) (ton/yr)**	**$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[12] (ton/yr)**	**CO (ton/yr)**	**Sulfuric Acid Mist (ton/yr)**	**Pb (ton/yr)**	**Hg (ton/yr)**	**Be (ton/yr)**	**H_2S (ton/yr)**	**Total Reduced Sulfur (ton/yr)**
Project Emission Increase (PEI) New Units[2]	202.5	464.4	78.8	125.8	367.4	12.93	5.18E-03	0.002	0.000135	14.8	14.8
PEI Affected Units[3]	23.1	(7.6)	60.1	90.9	174.5	(0.18)	3.55E-02	0.0004	0.000497	-	-
PEI	**225.6**	**456.7**	**138.9**	**216.7**	**541.8**	**12.7**	**4.07E-02**	**0.002**	**0.00063**	**14.8**	**14.8**
PSD Significant Emission Rate (SER)	**40.0**	**40.0**	**25.0**	**15.0**	**100.0**	**7.0**	**6.00E-01**	**0.1**	**0.0004**	**10.0**	**10.0**
Significant Project Emission Increase?	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes
Past Contemporaneous Changes											
NOx SIP Call - 3SPS (Permit No. 089-16586-0000) Effective Date: 1/30/2003	-	-	-	-	-	-					
FBI HWC MACT Project (Permit No. 089-16960-00453) Effective Date: 5/27/2003	-	-	-	-	-	-					
Consent Decree - No oil burning & FCU CO limits (Permit No. 089-15202-00003) Effective Date: 6/1/2003	-	-	(161.8)	(161.8)	-	(123.6)	(0.05880)	(0.00110)	(0.00571)		
DDU Debottlenecking Project (Permit No. 089-17230-00453) Effective Date: 9/10/2003	1.1	24.2	0.8	0.8	8.1	0.0					
CRU Conversion Project (Permit No. 089-15052-00453) Effective Date: 7/11/2003	2.2	23.9	1.6	1.6	33.9	0.7					
Sufur Pit Control Effective Date: 10/2003										(20.1)	(20.1)
ULSD Project (Permit No. 089-19754-00453) Effective date: 11/17/2003 Project Emissions excluding heater emissions.	8.4	2.0	0.1	0.1	1.6	0.0					
MACT II Project (Permit No. 089-19041-00453) Effective date: 7/15/2004	-	-	-	-	-	-					
Tank 3900 Modifications (Permit No. 089-21591-00453) Effective Date: 10/12/2005	0.8	-	-	-	-	-					
Steam to US Steel (Permit No. 089-21879-00003) Effective date: 11/18/2005	-	-	-	-	-	-					
Oxidizers on Remediation (Permit No. 089-21682-00453) Effective date: 12/20/2005	0.7	0.6	0.0	0.0	0.5	0.0					
Shutdown of Tank 3703[4] Effective date: 2/28/2006	(7.4)	-	-	-	-	-					
Sour Water Tank (TK 410) (Permit No. 089-23341-00453) Effective date: 8/25/06	2.8					-					
Asphalt Infrastructure Project (Increases) (Permit No. 089-24068-00453) Effective date: 2/20/07	1.9	6.4	1.0	1.0	10.8	0.0					
Asphalt Infrastructure Project (Decreases)[4] Submitted: 10/13/06	(3.8)					-					
Tank Cleaning Project (Permit No. 089-24258-00453) Effective date: 3/30/2007	6.8	24.7	1.8	2.0	5.4	0.1					
Net Emissions Increase (NEI) with Past Contemporaneous Changes	**239.0**	**538.5**	**(17.5)**	**60.5**	**602.2**	**(110.0)**	**-1.81E-02**	**1.23E-03**	**-5.08E-03**	**(5.3)**	**(5.3)**
Creditable Emission Reductions											
Coker[5] - Shutdown Heaters	(3.7)	(81.0)	(1.3)	(2.7)	(68.0)	(0.6)	-3.33E-04	-1.22E-04	-8.00E-06	-	-
NEI - Coker Shutdown Heaters	**235.3**	**457.6**	**(18.7)**	**57.8**	**534.2**	**(110.6)**	**-1.85E-02**	**1.10E-03**	**-5.08E-03**	**(5.3)**	**(5.3)**
Coker[5] - Shutdown Fugitives	(21.3)									-	-
NEI - Coker Shutdown Fugitives	**214.0**	**457.6**	**(18.7)**	**57.8**	**534.2**	**(110.6)**	**-1.85E-02**	**1.10E-03**	**-5.08E-03**	**(5.3)**	**(5.3)**
Beavon-Stretford TGU[5] - Shutdown	(0.2)	(3.4)	(0.1)	(0.3)	(2.9)	(0.0)	-1.64E-05	-6.04E-06	-3.95E-07	(2.3)	(62.5)
NEI - Beavon-Stretford TGU Shutdown	**213.9**	**454.1**	**(18.8)**	**57.5**	**531.3**	**(110.6)**	**-1.85E-02**	**1.10E-03**	**-5.08E-03**	**(7.6)**	**(67.8)**
SBS TGU[5] - Shutdown	(0.1)	-	(0.0)	(0.1)	-	(0.2)	-9.86E-06	-3.62E-06	-2.37E-07	-	-
NEI - SBS TGU - Shutdown	**213.7**	**454.1**	**(18.8)**	**57.4**	**531.3**	**(110.8)**	**-1.85E-02**	**1.10E-03**	**-5.08E-03**	**(7.6)**	**(67.8)**
SBS Cooling Tower[5] - Shutdown	(0.4)	-	(0.8)	(0.8)		-				-	-
NEI - SBS Cooling Tower - Shutdown	**213.4**	**454.1**	**(19.7)**	**56.6**	**531.3**	**(110.8)**	**-1.85E-02**	**1.10E-03**	**-5.08E-03**	**(7.6)**	**(67.8)**
SRU Incinerator[5] - Shutdown	(0.3)	(5.6)	(0.1)	(0.4)	(5.0)	(0.0)	-2.66E-05	-9.78E-06	-6.39E-07	-	-
NEI - SRU Incinerator - Shutdown	**213.1**	**448.6**	**(19.8)**	**56.2**	**526.3**	**(110.8)**	**-1.85E-02**	**1.09E-03**	**-5.08E-03**	**(7.6)**	**(67.8)**
12PS[5] - Shutdown Heater H-2	(2.6)	(15.0)	(0.9)	(3.7)	(0.0)	(0.5)	-2.40E-04	-8.82E-05	-5.76E-06	-	-
NEI - Shutdown 12 PS Heater H-2	**210.4**	**433.6**	**(20.7)**	**52.5**	**526.3**	**(111.3)**	**-1.87E-02**	**9.97E-04**	**-5.09E-03**	**(7.6)**	**(67.8)**
12PS[5] - Shutdown Heaters H-1AS/AN	(2.8)	(117.9)	(1.0)	(3.9)	(35.4)	(0.6)	-2.55E-04	-9.38E-05	-6.13E-06	-	-
NEI - Shutdown 12 PS Heaters H-1AS/AN	**207.6**	**315.7**	**(21.6)**	**48.6**	**490.9**	**(111.9)**	**-1.90E-02**	**9.03E-04**	**-5.10E-03**	**(7.6)**	**(67.8)**
12PS[5] - Shutdown Heater H-1CN	(1.0)	(14.8)	(0.4)	(0.8)	(12.4)	(0.3)	-9.34E-05	-3.43E-05	-2.24E-06	-	-
NEI - Shutdown 12 PS Heater H-1CN	**206.6**	**300.9**	**(22.0)**	**47.9**	**478.5**	**(112.2)**	**-1.91E-02**	**8.69E-04**	**-5.10E-03**	**(7.6)**	**(67.8)**
12PS[5] - Shutdown Heater H-1B	(3.9)	(202.7)	(1.3)	(5.4)	(60.8)	(0.7)	-3.54E-04	-1.30E-04	-8.50E-06	-	-
NEI - Shutdown 12 PS Heater H-1B	**202.7**	**98.2**	**(23.3)**	**42.5**	**417.7**	**(112.9)**	**-1.94E-02**	**7.39E-04**	**-5.11E-03**	**(7.6)**	**(67.8)**
12PS[5] - Shutdown Heater H-1CX	(5.1)	(79.4)	(1.8)	(3.5)	(66.1)	(1.0)	-4.66E-04	-1.71E-04	-1.12E-05	-	-
NEI - Shutdown 12 PS Heater H-1CX	**197.6**	**18.7**	**(25.1)**	**39.0**	**351.6**	**(113.9)**	**-1.99E-02**	**5.68E-04**	**-5.12E-03**	**(7.6)**	**(67.8)**
Fugitive Dust from Coke Storage, Handling, and Transport[5] - Shutdown	-		(179.1)	(43.9)				-6.19E-05	0.00E+00	-	-
NEI - Fugitive Dust from Coker Process	**197.6**	**18.7**	**(204.2)**	**(5.0)**	**351.6**	**(113.9)**	**-1.99E-02**	**5.06E-04**	**-5.12E-03**	**(7.6)**	**(67.8)**
No. 4 Treatment Plant[5] - Shutdown Fugitive Components	(0.2)									-	-
NEI - Shutdown Fugitive Components	**197.3**	**18.7**	**(204.2)**	**(5.0)**	**351.6**	**(113.9)**	**-1.99E-02**	**5.06E-04**	**-5.12E-03**	**(7.6)**	**(67.8)**
VRU 300[5] - Shutdown Fugitive Components	(6.2)										
NEI - Shutdown Fugitive Components	**191.2**	**18.7**	**(204.2)**	**(5.0)**	**351.6**	**(113.9)**	**-1.99E-02**	**5.06E-04**	**-5.12E-03**	**(7.6)**	**(67.8)**
LDAR - Control Existing Heavy Liquid Pumps	(27.3)	-	-	-	-					-	-
NEI - Control Existing HL Pumps	**163.9**	**18.7**	**(204.2)**	**(5.0)**	**351.6**	**(113.9)**	**-1.99E-02**	**5.06E-04**	**-5.12E-03**	**(7.6)**	**(67.8)**
Sulfur Loading Reduction										(8.4)	(8.4)
NEI - Sulfur Loading Reductions	**163.9**	**18.7**	**(204.2)**	**(5.0)**	**351.6**	**(113.9)**	**-1.99E-02**	**5.06E-04**	**-5.12E-03**	**(15.9)**	**(76.1)**
NEI with Creditable Emission Reductions	**163.9**	**18.7**	**(204.2)**	**(5.0)**	**351.6**	**(113.9)**	**-1.99E-02**	**5.06E-04**	**-5.12E-03**	**(15.9)**	**(76.1)**
Future Non-CXHO Contemporaneous Projects											
No. 1 Stanolind Power Station[6,10] - Shutdown	(8.6)		(2.8)	(11.2)	(268.0)	(1.5)	-7.34E-04	-2.69E-04	-1.76E-05		
NEI - 1SPS Shutdown	**155.3**	**18.7**	**(207.0)**	**(16.1)**	**83.6**	**(115.4)**	**-2.06E-02**	**2.37E-04**	**-5.14E-03**	**(15.94)**	**(76.14)**
3UF[6] - Shutdown Heaters H-1	(3.7)	(189.6)	(1.3)	(2.8)	(56.9)	(0.2)	-3.39E-04	-1.24E-04	-8.13E-06		
NEI - 3UF Heater H-1 Shutdown	**151.5**	**(170.9)**	**(208.3)**	**(18.9)**	**26.7**	**(115.6)**	**-2.10E-02**	**1.12E-04**	**-5.14E-03**	**(15.94)**	**(76.14)**
3UF[6] - Shutdown Heaters H-2 and F-7	(3.9)	(181.4)	(1.3)	(2.9)	(58.9)	(0.2)	-3.50E-04	-1.29E-04	-8.41E-06		
NEI - 3UF Heater H-2 and F-7 Shutdown	**147.7**	**(352.3)**	**(209.6)**	**(21.8)**	**(32.1)**	**(115.8)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
3UF[6,7] - Shutdown Reformer Section	(1.2)				(8.0)	(0.1)					
NEI - 3UF Reformer Section Shutdown	**146.5**	**(352.3)**	**(209.6)**	**(21.8)**	**(40.1)**	**(115.9)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
3UF[6] - Shutdown Fugitive Components	(10.8)										
NEI - 3UF Fugitive Components Shutdown	**135.7**	**(352.3)**	**(209.6)**	**(21.8)**	**(40.1)**	**(115.9)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
Marine Dock[8] - Install VRU or VCU	(175.4)	5.6			2.2						
NEI - Marine Dock VRU	**(39.8)**	**(346.7)**	**(209.6)**	**(21.8)**	**(37.9)**	**(115.9)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
Cooling Towers[9] - Install Drift Eliminator on Cooling Tower 2			(15.6)	(15.6)							
NEI - Cooling Tower 2 Drift Eliminator	**(39.8)**	**(346.7)**	**(225.1)**	**(37.3)**	**(37.9)**	**(115.9)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
Cooling Towers[9] - Install Drift Eliminators on Cooling Tower 3			(40.4)	(40.4)							
NEI - Cooling Tower 3 Drift Eliminator	**(39.8)**	**(346.7)**	**(265.5)**	**(77.7)**	**(37.9)**	**(115.9)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
Cooling Towers[9] - Install Drift Eliminators on Cooling Tower 4			(24.1)	(24.1)							
NEI - Cooling Tower 4 Drift Eliminator	**(39.8)**	**(346.7)**	**(289.6)**	**(101.7)**	**(37.9)**	**(115.9)**	**-2.13E-02**	**-1.62E-05**	**-5.15E-03**	**(15.94)**	**(76.14)**
Lakefront Fluidized Bed Incinerator[8] - Shutdown	(7.3)	(16.8)	(3.9)	(3.9)	(2.1)	(0.1)	-2.46E-03	-2.27E-03	-6.35E-05		
NEI - Shutdown FBI	**(47.0)**	**(363.5)**	**(293.5)**	**(105.7)**	**(40.0)**	**(116.1)**	**-2.38E-02**	**-2.28E-03**	**-5.22E-03**	**(15.94)**	**(76.14)**
Tank BT-002 Modification	0.6										
NEI - Tank BT-002 Modification	**(46.4)**	**(363.5)**	**(293.5)**	**(105.7)**	**(40.0)**	**(116.1)**	**-2.38E-02**	**-2.28E-03**	**-5.22E-03**	**(15.94)**	**(76.14)**
Boiler Project	27.2	322.0	9.2	40.0	118.9	2.3	2.43E-03	8.92E-04	5.83E-05		
NEI - Boiler Project	**(19.2)**	**(41.5)**	**(284.3)**	**(65.7)**	**78.9**	**(113.8)**	**-2.14E-02**	**-1.39E-03**	**-5.16E-03**	**(15.94)**	**(76.14)**
3 SPS SCR Project	5.6	2.2	1.6	22.9	(106.7)	0.9	4.25E-04	1.56E-04	1.02E-05		
NEI - 3SPS SCR	**(13.7)**	**(39.3)**	**(282.7)**	**(42.8)**	**(27.8)**	**(112.9)**	**-2.09E-02**	**-1.23E-03**	**-5.15E-03**	**(15.94)**	**(76.14)**
Fire Pump Engines	0.7	5.0	0.3	0.3	1.7	0.0					
NEI - Fire Pump Engines	**(12.9)**	**(34.3)**	**(282.4)**	**(42.5)**	**(26.2)**	**(112.9)**	**-2.09E-02**	**-1.23E-03**	**-5.15E-03**	**(15.94)**	**(76.14)**
Thermal Desorption	2.4	5.2	0.5	0.8	1.3	0.1	3.15E-04	1.05E-04	1.05E-04		
NEI - Thermal Desorption System	**(10.5)**	**(29.1)**	**(281.9)**	**(41.7)**	**(24.9)**	**(112.8)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
Tank 8 Replacement	6.1										
NEI - Tank 8 Replacement	**(4.4)**	**(29.1)**	**(281.9)**	**(41.7)**	**(24.9)**	**(112.8)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
Tank 3637	0.2										
NEI - Tank 3637	**(4.2)**	**(29.1)**	**(281.9)**	**(41.7)**	**(24.9)**	**(112.8)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
11A PS WARP	2.2	0.1	0.0	0.0	0.4	0.0	5.49E-07	2.01E-07	1.32E-08		
NEI - 11A PS WARP	**(2.0)**	**(29.0)**	**(281.9)**	**(41.7)**	**(24.5)**	**(112.8)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
11C PS WARP	(3.9)	0.1	0.0	0.0	0.5	0.1	6.01E-07	2.21E-07	1.44E-08		
NEI - 11C PS WARP	**(5.9)**	**(29.0)**	**(281.9)**	**(41.6)**	**(24.0)**	**(112.7)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
FCU500 WARP[11]	1.0	0.0	0.0	0.0	0.1	0.0	1.79E-07	6.56E-08	4.29E-09		
NEI - FCU500 WARP	**(4.9)**	**(28.9)**	**(281.9)**	**(41.6)**	**(23.9)**	**(112.7)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
FCU600 WARP	(1.5)	0.0	0.0	0.0	0.1	0.0	1.79E-07	6.56E-08	4.29E-09		
NEI - FCU600 WARP	**(6.4)**	**(28.9)**	**(281.9)**	**(41.6)**	**(23.7)**	**(112.7)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
FCU600 TAR	0.3										
NEI - FCU600 TAR	**(6.1)**	**(28.9)**	**(281.9)**	**(41.6)**	**(23.7)**	**(112.7)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
VRU100/200 WARP	(0.2)	0.0	0.0	0.0	0.0	0.0	3.15E-08	1.16E-08	7.55E-10		
NEI - VRU100/200 WARP	**(6.3)**	**(28.9)**	**(281.9)**	**(41.6)**	**(23.7)**	**(112.7)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.94)**	**(76.14)**
NEI with Non-CXHO Contemporaneous Projects	**(6.3)**	**(28.9)**	**(281.9)**	**(41.6)**	**(23.7)**	**(112.7)**	**-2.06E-02**	**-1.13E-03**	**-5.04E-03**	**(15.9)**	**(76.1)**
NEI Project Emissions	**-6.3**	**-28.9**	**-281.9**	**-41.6**	**-23.7**	**-112.7**	**-0.021**	**-0.00113**	**-0.00504**	**-15.9**	**-76.1**
PSD SERs (tpy)	**40.0**	**40.0**	**25.0**	**15.0**	**100.0**	**7.0**	**0.6**	**0.1**	**0.0004**	**10**	**10**
Significant Net Emissions Increase?	No	No	No	No	No	No	No	No	No	No	No
Pollutant	**VOC (ton/yr)**	**NOx (ton/yr)**	**PM (Filterable) (ton/yr)**	**$PM_{10}/PM_{2.5}$ (Filterable + Condensable)[13] (ton/yr)**	**CO (ton/yr)**	**Sulfuric Acid Mist (ton/yr)**	**Pb (ton/yr)**	**Hg (ton/yr)**	**Be (ton/yr)**	**H_2S (ton/yr)**	**Total Reduced Sulfur (ton/yr)**

[1] Selected 24-month period is based on calendar years.
[2] PEI New Units from Table C.81.
[3] PEI Affected Units from "Evaluation of Project Impacts on Existing Units" (Tables C.71 through C.80)
[4] Emissions decreases for past contemporaneous projects are being made enforceable as part of the CXHO Project. The emissions decreases were documented in the respective permit applications.
[5] Unit shutdown values based on average past actual emissions for baseline period.
[6] Unit shutdown values for future non-CXHO contemporaneous projects are based on a 24-month period average past actual emissions.
[7] 3UF Reformer emissions based on data recorded by BP Whiting PI data collection system.
[8] Marine Dock VOC emissions based on 2003-2004 total average emissions controlled to 10 mg of VOC/L of throughput for gasoline loading.
[9] Existing Cooling Towers 2, 3, and 4 will be controlled to 0.001% liquid drift. Note half of the Cooling Tower 2 modules are already controlled to 0.001% liquid drift. Contemporaneous to the CXHO Project the other modules will be controlled with high efficiency drift eliminators.
[10] No creditable NO_x decrease was taken for the shutdown of the 1SPS boilers per the consent decree.
[11] The FCU 500 WARP emergency/malfunction flaring emissions are assumed to be equivalent to the FCU 600 WARP emissions. The projects will be similar; however, the FCU 500 WARP release rates have not yet been estimated since the project design is not yet complete.
[12] Based on interim guidance from US EPA, $PM_{2.5}$ is evaluated based on significant emission rate thresholds established for PM_{10}. The current PM_{10} SIP limits filterable PM_{10} emissions and compliance is based on reference test method 201A (which o filterable particulate matter). Although not required, BP Whiting has conservatively adjusted the PM_{10} baseline based on the PM_{10} SIP limits for PSD applicability purposes, which includes both filterable and condensable PM_{10}. $PM_{2.5}$ emissions are no by the Lake County PM_{10} SIP, however, to be conservative, BP Whiting has adjusted $PM_{2.5}$ baseline emissions in the same manner as for PM_{10} emissions.

Table C.82a. Sulfur Dioxide Project Net Emission Increases per Consent Decree[1] Requirements

Project Emissions Baseline 24-Month Period[2]	2003-2004
Pollutant	**SO_2 (ton/yr)**
Project Emission Increase (PEI) New Units[3]	281.7
PEI Affected Units[4]	(4.0)
PEI	**277.7**
PSD Significant Emission Rate (SER)	**40.0**
Significant Project Emission Increase?	Yes

Sulfur Dioxide Netting Analysis

Increases from "Lower Sulfur Fuels Units"	
Affected Unit Project Increases	
BOU - Heater F-401	0.8
CFHU - Heaters F-801A, F-801B, F-801C	2.8
CRU - Heaters F-101 and F-102	1.1
4UF - Heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, and F-8B	21.8
FCU 500	58.9
New Unit Project Increases	
DHT - Heater B-601A	0.1
GOHT - Heaters F-901A and F-901B	4.6
Hydrogen Plant (3rd Party SMR) - Heaters HU-1 and HU-2	1.2
Past Contemporaneous Changes	
DDU Debottlenecking Project (Permit No. 089-17230-00453) Effective Date: 9/10/2003	0.1
CRU Conversion Project (Permit No. 089-15052-00453) Effective Date: 7/11/2003	15.9
ULSD Project (Permit No. 089-19754-00453) Effective date: 11/17/2003 Project Emissions excluding heater emissions.	0.1
Consent Decree[1] Decreases that Offset Increases at "Lower Sulfur Fuels Units"	
Consent Decree - No oil burning & FCU CO limits (Permit No. 089-15202-00003) Effective Date: 6/1/2003	(269.4)
Total Increases from "Lower Sulfur Fuels Units"	107.3
Total Consent Decree[1] Decreases that Offset Increases at "Lower Sulfur Fuels Units'	(269.4)
Net Emissions for "Lower Sulfur Fuels Units"[5]	-

Increases from Other "Netting/Offset Generating Units"	
New Unit Project Increases	
12 PS Heaters - H-101A, H-101B, and H-102	50.4
#2 Coker - Heaters H-201, H-202, and H-203	30.2
Future Non-CXHO Contemporaneous Projects	
Boiler Project	49.8
3 SPS SCR Project	19.0
Consent Decree[1] Decreases that Offset Other "Netting/Offset Generating Units"	
Consent Decree - Reduce FCU 600 SO_2 limit to 50 ppm	(160.9)
Total Increases from Other "Netting/Offset Generating Units"	149.5
Total Consent Decree[1] Decreases that Offset Other "Netting/Offset Generating Units'	(160.9)
Net Emissions for Other "Netting/Offset Generating Units"[6]	-

Increases from Remaining Units	
New Unit Project Increases	
SRU	
New Claus Train D	
New Claus Train E	
Claus Offgas Treaters 1 and 2	194.8
Flares	
GOHT Flare	
Pilot Emissions	0.0
Purge Emissions	0.2
South Flare	
Pilot Emissions	0.0
Purge Emissions	0.2
HU Flare	
Pilot Emissions	0.0
Past Contemporaneous Changes	
Oxidizers on Remediation (Permit No. 089-21682-00453) Effective date: 12/20/2005	0.2
Asphalt Infrastructure Project (Increases) (Permit No. 089-24068-00453) Effective date: 2/20/07	0.1
Tank Cleaning Project (Permit No. 089-24258-00453) Effective date: 3/30/2007	2.9
Future Non-CXHO Contemporaneous Projects	
Fire Pump Engines	0.1
Thermal Desorption	1.8
11A PS WARP	0.3
11C PS WARP	2.6
FCU500 WARP	0.0
FCU600 WARP	0.0
VRU100/200 WARP	0.0
Decreases that Offset Increases at Remaining Units	
Affected Unit Project Increases	
11A PS - Heater H-1X, H-2, and H-3	(7.5)
11C PS - Heaters H-200 and H-300	(4.2)
ARU - Heaters F-200A and F-200B	(17.8)
DDU - Heaters WB-301 and WB-302	(2.1)
ISOM - Heater H-1	(5.5)
HU - Heater B-501	(36.8)
FCU 600 - Reduce SO_2 to 37 ppm outlet concentration	(15.4)
Creditable Emissions Reductions	
Coker - Shutdown Heaters	(12.7)
Beavon-Stretford TGU - Shutdown	(8.7)
SBS TGU - Shutdown	(3.5)
SRU Incinerator - Shutdown	(0.0)
12PS - Shutdown Heater H-2	(11.9)
12PS - Shutdown Heaters H-1AS/AN	(13.6)
12PS - Shutdown Heater H-1CN	(5.5)
12PS - Shutdown Heater H-1B	(16.1)
12PS - Shutdown Heater H-1CX	(21.5)
Future Non-CXHO Contemporaneous Projects	
No. 1 Stanolind Power Station - Shutdown	(32.8)
3UF - Shutdown Heaters H-1	(4.6)
3UF - Shutdown Heaters H-2 and F-7	(4.6)
3UF - Shutdown Reformer Section	(2.5)
Lakefront Fluidized Bed Incinerator - Shutdown	(2.8)
Total Increases from Remaining Units	203.3
Total Decreases that Offset Increases at Remaining Units	(230.1)
Net SO_2 Emissions for CXHO Projects	(26.7)

Net Emissions for "Lower Sulfur Fuels Units"	-
Net Emissions for Other "Netting/Offset Generating Units"	-
Net Emissions for Remaining Units	(26.7)
SO_2 NEI Project Emissions	**(26.7)**
PSD SERs (tpy)	**40.0**
Significant Net Emissions Increase?	No

1. United States, et. al. v. BP Exploration & Oil, et. Al.; Northern District of Indiana, Hammond Division; Civil Action No. 2:96 CV 095 RL.
2. Selected 24-month period is based on calendar years.
3. PEI New Units from Table C.81.
4. PEI Affected Units from "Evaluation of Project Impacts on Existing Units" (Tables C.71 through C.80)
5. The Consent Decree specifies that no more than ten percent (10%) of the SO_2 emission reduction credits generated by the cessation of oil burning could be used for netting SO_2 emissions increases that result from the construction or modification of "lower sulfur fuels units" that meet the criteria for "netting/offset generating units". Therefore, any reduction beyond the emissions increases from "lower sulfur fuels units" cannot be used to offset other increases and are not carried forward in this netting analysis
6. The Consent Decree specifies that no more than ten percent (10%) of the SO_2 emission reduction credits generated by the FCU 600 SO_2 emissions reduction to 50 ppm could be used for netting SO_2 emissions increases that result from the construction or modification of "netting/offset generating units". Therefore, any reduction beyond the emissions increases from "netting/offset generating units" cannot be used to offset other increases and are not carried forward in t netting analysis.

Table C.83. Project VOC de minimis Test

Per 326 IAC 2-3-1(q), a de minimis increase of VOC from a modification in a serious or severe ozone nonattainment area, means an increase that does not exceed twenty-five (25) tons per year when the net emissions increases from the proposed modification are aggregated on a pollutant specific basis with all other net emissions increases from the source over a five (5) consecutive calendar year period prior to, and including, the year of the modification. This modification is expected to commence operation in 2011, and therefore the net emissions changes from projects taking place between 2007 and 2011 have been considered for this evaluation.

Project Emissions Baseline 24-Month Period[1]	**2001-2002**
	VOC (ton/yr)
Project Emission Increase (PEI) New Units[2]	202.5
PEI Affected Units[3]	23.1
Coker[5] - Shutdown Heaters	(3.7)
Coker[5] - Shutdown Fugitives	(21.3)
Beavon-Stretford TGU[5] - Shutdown	(0.2)
SBS TGU[5] - Shutdown	(0.1)
SBS Cooling Tower[5] - Shutdown	(0.4)
SRU Incinerator[5] - Shutdown	(0.3)
12PS[5] - Shutdown Heater H-2	(2.6)
12PS[5] - Shutdown Heaters H-1AS/AN	(2.8)
12PS[5] - Shutdown Heater H-1CN	(1.0)
12PS[5] - Shutdown Heater H-1B	(3.9)
12PS[5] - Shutdown Heater H-1CX	(5.1)
No. 4 Treatment Plant[5] - Shutdown Fugitive Components	(0.2)
VRU 300[5] - Shutdown Fugitive Components	(6.2)
PEI	**177.7**

5-Year Contemporaneous Projects

Lakefront FBI Shutdown	(7.3)
Asphalt Infrastructure Project (Increases) (Permit No. 089-24068-00453) (Effective date: 2/20/07)	1.9
Asphalt Infrastructure Project (Decreases)[4] (Submitted: 10/13/06)	(3.8)
Tank Cleaning Project (Permit No. 089-24258-00453) (Effective date: 3/30/2007)	6.8
No. 1 Stanolind Power Station[6] - Shutdown	(8.6)
3UF[6] - Shutdown Heater H-1	(3.7)
3UF[6] - Shutdown Heaters H-2 and F-7	(3.9)
3UF[6,7] - Shutdown Reformer Section	(1.2)
3UF[6] - Shutdown Fugitive Components	(10.8)
Marine Dock[8] - Install VRU or VCU	(175.4)
Tank BT-002 Modification	0.6
Boiler Project	27.2
SCR	5.6
Fire Pump Engines	0.7
Thermal Desorption	2.4
Tank 8	6.1
Tank 3637	0.2
11A PS WARP	2.2
11C PS WARP	(3.9)
FCU500 WARP	1.0
FCU600 WARP	(1.5)
FCU600 TAR	0.3
VRU100/200 WARP	(0.2)
LDAR - Control Existing Heavy Liquid Pumps	(27.3)

NEI Project Emissions	**-14.8**
NSR SERs (tpy)	**25.0**
Significant Net Emissions Increase?	No
Pollutant	**VOC (ton/yr)**

[1] Selected 24-month period is based on calendar years.
[2] PEI New Units from Table C.81.
[3] PEI Affected Units from "Evaluation of Project Impacts on Existing Units" (Tables C.71 through C.80)
[4] Emissions decreases for past contemporaneous projects are being made enforceable as part of the CXHO Project. The emissions decreases were documented in the respective permit applications.
[5] Unit shutdown values based on average past actual emissions for baseline period.
[6] Unit shutdown values for future non-CXHO contemporaneous projects are based on a 24-month period average past actual emissions.
[7] 3UF Reformer emissions based on data recorded by BP Whiting PI data collection system.
[8] Marine Dock VOC emissions based on 2003-2004 total average emissions controlled to 10 mg of VOC/L of throughput for gasoline loading.

Table C.84. PM_{10} (filterable) SIP Limits

Process Heaters and Boilers

Code	Process Unit	Rated Capacity[3]	PM_{10} SIP Limits		Annualized PM_{10} SIP Emissions
			lb/MMBtu	lb/hr	ton/yr
Crude and Coking					
11A PS					
Oth	H-1X	250	0.031	6.867	30.1
Oth	H-2	45	0.032	1.440	6.3
Oth	H-3	55	0.031	1.704	7.5
11C PS					
Oth	H-200	249.5	0.032	7.866	34.5
Oth	H-300	180	0.031	4.931	21.6
Coker					
SD	H-101	200	0.004	0.741	3.2
SD	H-102				
SD	H-103				
SD	H-104				
12PS					
SD	H-1AN	121.5	0.025	16.348	71.6
SD	H-1AS	121.5			
Oth	H-1B	243			
SD	H-2	174			
SD	H-1CN	120	0.004	0.444	1.9
Oth	H-1CX	410	0.004	0.924	4.0
Hydroprocessing					
3UF					
Mod	H-1[4]	240	0.004	0.852	3.7
SD	H-2	185	0.004	0.685	3.0
SD	F-7	23	0.004	0.085	0.4
4UF					
Oth	F-1	68	0.004	1.459	6.4
Oth	F-8A	163			
Oth	F-8B	163			
Oth	F-2	286	0.004	1.059	4.6
Oth	F-3	242	0.004	0.896	3.9
Oth	F-4	137	0.004	1.060	4.6
Oth	F-5	99			
Oth	F-6	49			
Oth	F-7	52	0.004	0.159	0.7
ARU					
Oth	F-200A	249.5	0.004	0.924	4.0
Oth	F-200B	249.5	0.004	0.924	4.0
BOU					
Oth	F-401	35	0.004	0.130	0.6
CFHU					
Oth	F-801A	66.5	0.004	0.246	1.1
Oth	F-801B				
Oth	F-801C	60.00			
CRU					
Oth	F-101	72	0.004	0.267	1.2
Oth	F-102	60	0.004	0.290	1.3
DDU					
Oth	WB-301	64.8	0.004	0.250	1.1
Oth	WB-302	83.7	0.004	0.240	1.1
ISOM					
Mod	H-1	190	0.004	0.704	3.1
HU					
Oth	B-501	366.3	0.009	3.340	14.6
Utilities					
1SPS					
SD	Boiler 3	265	0.016	15.809	69.2
SD	Boiler 4	265			
SD	Boiler 5	265	0.016	13.224	57.9
SD	Boiler 6	265			
SD	Boiler 7	265			
Fluidized Catalytic Cracking[1]					
Oth	FCU 500	115 bbl/day	1.220	73.20	320.6
Mod[5]	FCU 600	80 bbl/day	1.10	55.00	240.9
Sulfur Recovery Complex[2]					
SD	Beavon-Stretford TGU	24.3	0.110	0.103	0.5

[1] PM_{10} SIP Limit for the FCU 500 and FCU 600 are provided in lb/1,000 lb coke burned, not lb/MMBtu.

[2] PM_{10} SIP Limit for the Beavon-Stretford TGU is provided in lb/ton, not lb/MMBtu.

[3] Rated Capacity from Title V Permit (Permit No. T089-6741-00453)

[4] Rated Capacity for 3UF Heater H-1 based on rated capacity used to establish PM SIP limits.

[5] As part of the CXHO project, BP Whiting will be making modifications to the main fractionator tower.

Table C.85 Concrete Crushing Emissions

Total Concrete to be Crushed	18,000.0	tons
Total Transfer Points	2	
Hours of Operation per day	10	hours/day
Concrete Processed per day	1,200	tons/day
Concrete Processed per hour	120	tons/hour

Emission Calculation Variables[1]	PM	$PM_{10}/PM_{2.5}$	Unit
Uncontrolled Tertiary Crushing Factor	0.0054	0.0024	lb/Ton
Conveyor Transfer Point Factor	0.0030	0.0011	lb/Ton

Emission Calculation

Concrete Crushing Emissions	PM		PM_{10}		$PM_{2.5}$	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Crushing Emissions	0.6	0.0	0.3	0.0	0.3	0.0
Transfer Emissions	0.4	0.0	0.1	0.0	0.1	0.0
Total	1.0	0.08	0.4	0.03	0.4	0.03

1. Emission Factors from AP-42 Section 11.19.2, Table 11.19.2-2 (August 2004)

Table C.86. Increases and Decreases in Sewer Emissions Components Associated with the CXHO Project

EQUIPMENT TYPE	UNIT																				
	4UF	ARU	BOU	ISOM	VRU 300	DDU	DHT	12PS	OSBL	3UF	Coker 1	No. 4 TP	#1 SPS	GOHT	HU-2	Coker 2	SRU D-Claus	SRU E-Claus	SCOT 1	SCOT 2	TOTALS
Component Type	Modified	Modified	Modified	Modified	Modified	Modified	Modified	Modified	Modified	Shutdown	Shutdown	Shutdown	Shutdown	New	New	New	New	New	New	New	
Atmospheric Drain Hub	0	0	0	4	-65	4	0	0	16	-48	-53	-60	0	31	31	80	10	10	0	0	-40
Catch Basin (Pad or Paving Drain)[‡]	0	0	0	2	0	2	0	0	8	0	0	0	0	15	15	51	5	5	0	0	102
Inspection Points	0	0	0	0	0	0	0	0	2	0	0	0	0	3	3	4	1	1	0	0	13
Cleanouts	0	0	0	0	0	0	0	0	2	0	0	0	0	4	4	5	1	1	0	0	17
Above Ground Sewer Pump Out Points	0	0	0	0	0	0	0	0	10	0	0	0	0	20	20	24	7	7	0	0	87
Sum of Drains																					**78**
Manhole/Junction Box w/o Vent	0	0	0	0	0	0	0	0	5	0	0	0	0	10	10	45	3	3	0	0	77
Manhole/Junction Box w/ CC and/or Vent	0	0	0	0	0	0	0	0	2	0	0	0	0	3	3	4	1	1	0	0	13
OSBL Manholes Per Unit - Sealed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flare / Degassing/ KO Tanks (ie Above Ground Junction Boxes)	0	0	0	0	0	0	0	0	1	0	0	0	0	2	2	2	1	1	0	0	9
Sealed cover sumps - Gas Traps or other sumps	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	9	0	0	0	0	12
Total Manholes/Junction Boxes/Sealed Sumps																					**111**
Below Grade Oily Water Separator - Fixed Roof	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Below Grade Oily Water Separator - Floating Roof	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OSBL Sumps/OWS Per Unit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total In ground OWS/Sumps																					**0**
Tanks DGO / LGO / Sour Water service	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Above Ground Oil Water Separator Tanks	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	1	0	0	0	0	4
Total Above Ground Tanks																					**4**

Assumptions:

All units will meet Benzene Neshaps Compliance Standards

No COV's will be utilized

Estimated Flow Rates for Oil Water Separator Tanks (Based on Design Flow Rate Data):

Unit	Estimated Flow Rate (MMGPD)	Flow Rate (1,000 liters/day)
OSBL	0.02	75.7
GOHT	0.3	1135.5
Coker 2	0.07	264.95
HU 2	0.015	56.775

Emissions Calculations for Sewer Components

Total Flow Rate =	1532.9

AP-42 Factors - Section 5-1 Petroleum Refining 1/95 - Calculations assume 50% control on drains versus uncontrolled drain emissions in AP-42		No. of Units	Units of 1000 liters of flow per day	Emission Factor Value	Emission Factor Units	Total Emissions (kg/hr)
EMISSION INCREASES						
Drains Controlled[1]		78		0.3	kg/day/unit	1.12
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)		22		0.03	kg/day/unit	0.03
Sealed Manholes		89		0.16	kg/day/unit	0.59
Oil Water Separator and Auxillaries						
	OWS	0		0.024	**kg/1000 liters flow**	0.000
	Slop oil tanks/OW surge tanks				Use Tanks Program	0.00
	OWS Abv Gr (API) Controlled	n/a	1532.9	0.024	**kg/1000 liters flow**	1.533
Subtotal for Emission Increases						3.27
EMISSION DECREASES						
Area Drains Controlled				0.3	kg/day/unit	0.00
Area Drains Uncontrolled				0.7	kg/day/unit	0.00
Process Drains Controlled				0.3	kg/day/unit	0.00
Process Drains Uncontrolled				0.7	kg/day/unit	0.00
Catch Basins Controlled				0.3	kg/day/unit	0.00
Catch Basins Uncontrolled				0.7	kg/day/unit	0.00
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)				0.03	kg/day/unit	0.00
Sealed Manholes				0.16	kg/day/unit	0.00
Junction Boxes/Manholes Uncontrolled				0.7	kg/day/unit	0.00
Oil Water Separator and Auxillaries						
	OWS (API) Controlled			0.024	kg/1000 liters	0.00
	OWS (API) Uncontrolled			0.6	kg/1000 liters	0.00
	Slop oil tanks/OW surge tanks					0.00
	OWS Abv Gr (API) UnControlled			0.6	kg/1000 liters	0.00
	OWS Abv Gr (API) Controlled			0.024	kg/1000 liters	0.00
Subtotal for Emission Decreases						0.00
NET EMISSIONS					kg/hr	3.27
					lb/d	172.85
					lb/yr	63090
					TPY	**31.5**

Notes:

[1] The number of catch basins are provided, but are not included in the total emissions calculations since they are storm water catch basins. Emissions from these catch basins are expected to be negligible in comparison to the other process sewer drains included.

Uncontrolled emissions factors from AP-42 Section 5.1, Table 5.1-3 (January 1995)

Emission Source	VOC Emissions Factor per Component	Units	Source*	Ref.
Uncontrolled Drain	0.69	Kg/day	AP-42 (e.g. 450/650)	Table 5.1-3
Controlled Drain (with water trap – 50% control of AP-42)	0.0145	Kg/hr	BIDa	Pg. 4-9
Sealed Manway Cover (gasketed – 77% of AP-42)	0.022	Kg/hr	BIDb	Pg. 2-23
Uncontrolled Junction Box (same as an Uncontrolled Drain)	0.029	Kg/hr	AP-42 (ref. BIDa)	Pg. 3-27
Controlled Junction Box (with carbon canister to comply with BWON – 5% of AP-42)	0.00145	Kg/hr	BIDa, BWON	Pg. 4-30, 61.349(a)(2)(C)(ii)
Uncontrolled OWS	0.6	Kg/1000 liters	AP-42	Table 5.1-2
Controlled OWS	0.024	Kg/1000 liters	AP-42	Table 5.1-2

*Notes:

BIDa - Background Information Document to Proposed NSPS QQQ, Feb. 1985.

BIDb - Background Information Document to Proposed NSPS QQQ, Dec. 1987.

AP-42 - AP 42, Fifth Edition, Volume I Chapter 5.1 Petroleum Refining, Jan. 1995.

Fugitive Emission Calculations for WARP at 11A Pipestill

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	5	0.5789	0.0013	2.0%	0.0643	95%	100%	0.01
Light Liquid	90	0.1878	0.0037	2.0%	0.6644	95%	100%	0.15
Heavy Liquid	7	0.00051	0.00051	2.0%	0.0036	30%	100%	0.01
Pumps								
Light Liquid	1	0.9630	0.0265	2.0%	0.0452	80%	100%	0.04
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	15	0.0827	0.00013	0.3%	0.0057	30%	100%	0.02
Light Liquid	163	0.0827	0.00013	0.3%	0.0616	30%	100%	0.19
Heavy Liquid	12	0.0827	0.00013	0.3%	0.0045	30%	100%	0.01
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves - Added[3]	1	3.728	0.0985	2.0%	0.1711	98%	100%	0.01
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
Total VOC Emissions Associated with Added Components (tons/yr):								0.45

Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	-23	0.1878	0.0037	2.0%	-0.1698	95%	100%	-0.04
Heavy Liquid	-8	0.00051	0.00051	2.0%	-0.0041	30%	100%	-0.01
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	-46	0.0827	0.00013	0.3%	-0.0174	30%	100%	-0.05
Heavy Liquid	-19	0.0827	0.00013	0.3%	-0.0072	30%	100%	-0.02
Total VOC Emissions Associated with Removed Components (tons/yr):								**-0.12**

Past Emissions from Relief Valves - Existing Controlled[3]	47	3.728	0.0985	2.0%	8.0412	90%	100%	3.52
Relief Valves - Existing Controlled[3]	47	3.728	0.0985	2.0%	8.0412	98%	100%	0.70
Emissions Reduction (Future - Past)								-2.82
Total VOC Emissions Associated with Added Components and Additional Controls (tons/yr):								**-2.50**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

[3] There is 1 new relief valve and 47 existing RV's - previously routed to the atmosphere (through the blowdown stack) that are now routed to the DDU flare. The existing RVs were previously controlled with a water spray chamber that is presumed to be capable of 90% control.

Increased Sewer Emissions from 11A WARP Project due to Added Equipment

EQUIPMENT TYPE	UNIT 11A PS - Estimated Counts	
Atmospheric Drain Hub	15	
Catch Basin (Pad or Paving Drain)	6	
Inspection Points	7	
Cleanouts	6	
Above Ground Sewer Pump Out Points		
Sum of Drains	**34**	*Does Not include Above ground pump out lines as are typically fugitive emissions included with fugitives*
Manhole/Junction Box w/o Vent		
Manhole/Junction Box w/ CC and/or Vent		
OSBL Manholes Per Unit - Sealed		
Flare / Degassing/ KO Tanks (ie Above Ground Junction Boxes)	0	
Sealed cover sumps - Gas Traps or other sumps		
Total Manholes/Junction Boxes/Sealed Sumps	**0**	
Below Grade Oily Water Separator - Fixed Roof		
Below Grade Oily Water Separator - Floating Roof		
OSBL Sumps/OWS Per Unit		
Total In ground OWS/Sumps	**0**	
Tanks DGO / LGO / Sour Water service		
Above Ground Oil Water Separator Tanks		
Total Above Ground Tanks	**0**	

Assumptions:

All units will meet Benzene Neshaps Compliance Standards

No COV's will be utilized

AP-42 Factors - Section 5-1 Petroleum Refining 1/95 - Calculations assume 50% control or drains versus uncontrolled drain emissions in AP-42		No. of Units	Units of 1000 liters of flow	Emission Factor Value	Emission Factor Units	Total Emissions (kg/hr)
EMISSION INCREASES						
Drains Controlled		34		0.3	kg/day/unit	0.49
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)		0		0.03	kg/day/unit	0.00
Sealed Manholes		0		0.16	kg/day/unit	0.00
Oil Water Separator and Auxillaries						
	OWS	0		0.024	**kg/1000 liters flow**	0.000
	Slop oil tanks/OW surge tanks				Use Tanks Program	0.00
	OWS Abv Gr (API) Controlled	0		0.024	**kg/1000 liters flow**	0.000
Subtotal for Emission Increases						0.49

EMISSION DECREASES						
Area Drains Controlled				0.3	kg/day/unit	0.00
Area Drains Uncontrolled				0.7	kg/day/unit	0.00
Process Drains Controlled				0.3	kg/day/unit	0.00
Process Drains Uncontrolled				0.7	kg/day/unit	0.00
Catch Basins Controlled				0.3	kg/day/unit	0.00
Catch Basins Uncontrolled				0.7	kg/day/unit	0.00
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)				0.03	kg/day/unit	0.00
Sealed Manholes				0.16	kg/day/unit	0.00
Junction Boxes/Manholes Uncontrolled				0.7	kg/day/unit	0.00
Oil Water Separator and Auxillaries						
	OWS (API) Controlled			0.024	kg/1000 liters	0.00
	OWS (API) Uncontrolled			0.6	kg/1000 liters	0.00
	Slop oil tanks/OW surge tanks					0.00
	OWS Abv Gr (API) UnControlled			0.6	kg/1000 liters	0.00
	OWS Abv Gr (API) Controlled			0.024	kg/1000 liters	0.00
Subtotal for Emission Decreases						0.00

NET EMISSIONS

kg/hr	0.49
lb/d	25.89
lb/yr	9451
TPY	**4.7**

Notes:

Emission Source		Units	Source*
Uncontrolled Drain	0.69	Kg/day	AP-42 (e.g. 450/650)
Controlled Drain (with water trap – 50% control of AP-42)	0.0145	Kg/hr	BIDa
Sealed Manway Cover (gasketed – 77% of AP-42)	0.022	Kg/hr	BIDb
Uncontrolled Junction Box (same as an Uncontrolled Drain)	0.029	Kg/hr	AP-42 (ref. BIDa)
Controlled Junction Box (with carbon canister to comply with BWON – 5% of AP-42)	0.00145	Kg/hr	BIDa, BWON
Uncontrolled OWS	0.6	Kg/1000 liters	AP-42
Controlled OWS	0.024	Kg/1000 liters	AP-42

*Notes:
BIDa - Background Information Document to Proposed NSPS QQQ, Feb. 1985.
BIDb - Background Information Document to Proposed NSPS QQQ, Dec. 1987.
AP-42 - AP 42, Fifth Edition, Volume I Chapter 5.1 Petroleum Refining, Jan. 1995.

11A Emergency Relief Valves to the DDU Flare

Process Unit	Malfunction Rates		HHV BTU/scf	Sulfur ppm	Frequency #/year	Duration hours	VOC EF	VOC Unit	VOC lb/event[1]	VOC tpy	NO_X EF	NO_X Unit	NO_X lb/event[1]	NO_X tpy	SO_2 EF	SO_2 Unit	SO_2 lb/event[1]	SO_2 tpy	PM EF	PM Unit	PM lb/event[1]	PM tpy	$PM_{10}/PM_{2.5}$ EF	$PM_{10}/PM_{2.5}$ Unit	$PM_{10}/PM_{2.5}$ lb/event[1]	$PM_{10}/PM_{2.5}$ tpy	CO EF	CO Unit	CO lb/event[1]	CO tpy	Pb EF	Pb Unit	Pb lb/event[1]	Pb tpy	Hg EF	Hg Unit	Hg lb/day[1]	Hg tpy	Be EF	Be Unit	Be lb/day[1]	Be tpy
AZ-29	0.2466	MMscfh	4,420	1,000	2.0	0.33					0.068	lb/MMBtu	24.7	0.02	see below[2]		13.7	0.01	1.9	lb/MMscf	0.68	0.00	7.6	lb/MMscf	2.71	0.00	0.37	lb/MMBtu	134.4	0.13	5.0E-04	lb/MMscf	1.8E-04	1.78E-07	1.84E-04	lb/MMscf	6.5E-05	6.54E-08	1.20E-05	lb/MMscf	4.3E-06	4.27E-09
AZ-509	0.0356	MMscfh	4,000	150,000	1.0	0.33					0.068	lb/MMBtu	3.2	0.00	see below[2]		295.8	0.15	1.9	lb/MMscf	0.09	0.00	7.6	lb/MMscf	0.35	0.00	0.37	lb/MMBtu	17.6	0.01	5.0E-04	lb/MMscf	2.3E-05	1.16E-08	1.84E-04	lb/MMscf	8.5E-06	4.27E-09	1.20E-05	lb/MMscf	5.6E-07	2.79E-10
AZ-575/AZ-578	0.8331	MMscfh	5,060	1,000	1.0	0.33					0.068	lb/MMBtu	95.6	0.05	see below[2]		46.1	0.02	1.9	lb/MMscf	2.62	0.00	7.6	lb/MMscf	10.47	0.01	0.37	lb/MMBtu	519.9	0.26	5.0E-04	lb/MMscf	6.9E-04	3.44E-07	1.84E-04	lb/MMscf	2.5E-04	1.26E-07	1.20E-05	lb/MMscf	1.7E-05	8.27E-09
AZ-0589	0.1362	MMscfh	1,300	30,000	1.0	0.33					0.068	lb/MMBtu	4.0	0.00	see below[2]		226.3	0.11	1.9	lb/MMscf	0.11	0.00	7.6	lb/MMscf	0.44	0.00	0.37	lb/MMBtu	21.8	0.01	5.0E-04	lb/MMscf	2.9E-05	1.45E-08	1.84E-04	lb/MMscf	1.1E-05	5.31E-09	1.20E-05	lb/MMscf	6.9E-07	3.47E-10

	VOC[3]		NO_X		SO_2		PM		$PM_{10}/PM_{2.5}$		CO		Pb		Hg		Be	
Total Projected Actual Emissions				7.6E-02		0.30		2.1E-03		8.3E-03		0.41		5.5E-07		2.0E-07		1.3E-08
Major New Source Review Thresholds		40		40		40		25		15		100		0.6		0.1		0.1
Major New Source Review Triggered?		No		No		No		No		No		No		No		No		No

[1] Event emission rate represents one worst case emergency/malfunction scenario event. Annual emission rate represents the estimated annual average total duration of worst case emergency/malfunction events.

[2] SO_2 Emissions Calculation:

SO2 MW (lb/lb-mole)=		64

SO2 emissions are calculated based on the concentration of sulfur in the gas stream, the ideal gas law, and the molecular weight of SO2.

General Assumptions Used in Calculations

Variable	Value	Units
V	1,000,000	ft^3
P	14.7	psia
R	10.73	psia-ft^3/lbmol-R
T	527.7	R
md	2596.15	lbmols/MMscf
	385.1851	scf/lbmol

Ideal Gas Law used to determine the moles of gas per MSCF (P*V=n*R*T)

[3] Note that VOC emissions will actually decrease with respect to the current scenario where releases are not vented to the Flare since they will be controlled by the Flare; therefore, the potential VOC emissions associated with emergencies and malfunctions will decrease. Refer to the application text for more information.

Other Notes:

- Natural gas Higher Heating Value (Btu/scf) = 1020
- The 11A WARP project ties existing blowdown RVs to the DDU Flare header system and consists of emergency RVs only. Nitrogen will be used as the purge gas for the new header tie-ins.
- No modifications to the flare, flare knockout drum, or piping from the knockout drum to the flare required modifications to accommodate the worst case emergency relief scenarios when considering the worst case relief scenarios for the current operations
- Regulatory applicability for 40 CFR 63, Subpart CC will not change as a result of the project. Emergency RVs are not miscellaneous process vents per 40 CFR 63, Subpart CC since they are exempted from the definition in 40 CFR 63.641
- RV release gas combustion emission factors for PM/PM10/PM2.5, Lead, Mercury, and Beryllium are from AP-42 Section 1.4 (July 1998). Emission factors for VOC, NOx, and CO are from AP-42 Section 13.5 (September 1991). The emissions for SO2 are calculated
- The HHV and sulfur content was conservatively estimated based on the range of material that could be released. It was also conservatively assumed that each RV would lift one time per year, although this is an unlikely scenario.

Fugitive Emission Calculations for WARP at 11C Pipestill

Note that these counts also include work to control RVs for the 11B Coker that are part of the 11C WARP Project.

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	1	0.5789	0.0013	2.0%	0.0129	95%	100%	0.00
Light Liquid	51	0.1878	0.0037	2.0%	0.3765	95%	100%	0.08
Heavy Liquid	33	0.00051	0.00051	2.0%	0.0168	30%	100%	0.05
Pumps								
Light Liquid	2	0.9630	0.0265	2.0%	0.0905	80%	100%	0.08
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	10	0.0827	0.00013	0.3%	0.0038	30%	100%	0.01
Light Liquid	135	0.0827	0.00013	0.3%	0.0510	30%	100%	0.16
Heavy Liquid	71	0.0827	0.00013	0.3%	0.0268	30%	100%	0.08
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves - Added[3]	0	3.728	0.0985	2.0%	0.0000	98%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
Total VOC Emissions Associated with Added Components (tons/yr):								0.47

Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	-6	0.1878	0.0037	2.0%	-0.0443	95%	100%	-0.01
Heavy Liquid	-2	0.00051	0.00051	2.0%	-0.0010	30%	100%	0.00
Flanges								
Gas/Vapor	-2	0.0827	0.00013	0.3%	-0.0008	30%	100%	0.00
Light Liquid	-34	0.0827	0.00013	0.3%	-0.0128	30%	100%	-0.04
Heavy Liquid	-7	0.0827	0.00013	0.3%	-0.0026	30%	100%	-0.01
Total VOC Emissions Associated with Removed Components (tons/yr):								**-0.06**

Past Emissions from Relief Valves - Existing Controlled[3]	77	3.728	0.0985	2.0%	13.1739	90%	100%	5.77
Relief Valves - Existing Controlled[3]	77	3.728	0.0985	2.0%	13.1739	98%	100%	1.15
Emissions Reduction (Future - Past)								-4.62
Total VOC Emissions Associated with Added Components and Additional Controls (tons/yr):								**-4.21**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

[3] There are 2 new relief valves and 74 existing RV's - previously routed to the atmosphere (through the blowdown stack) that are now routed to the DDU flare. The existing RVs were previously controlled with a water spray chamber that is presumed to be capable of 90% control.

Increased Sewer Emissions from 11C WARP Project due to Added Equipment

EQUIPMENT TYPE	UNIT 11C PS - Estimated Counts	
Atmospheric Drain Hub	2	
Catch Basin (Pad or Paving Drain)	0	
Inspection Points	0	
Cleanouts	0	
Above Ground Sewer Pump Out Points		
Sum of Drains	**2**	*Does Not include Above ground pump out lines as are typically fugitive emissions included with fugitives*
Manhole/Junction Box w/o Vent		
Manhole/Junction Box w/ CC and/or Vent		
OSBL Manholes Per Unit - Sealed		
Flare / Degassing/ KO Tanks (ie Above Ground Junction Boxes)	0	
Sealed cover sumps - Gas Traps or other sumps		
Total Manholes/Junction Boxes/Sealed Sumps	**0**	
Below Grade Oily Water Separator - Fixed Roof		
Below Grade Oily Water Separator - Floating Roof		
OSBL Sumps/OWS Per Unit		
Total In ground OWS/Sumps	**0**	
Tanks DGO / LGO / Sour Water service		
Above Ground Oil Water Separator Tanks		
Total Above Ground Tanks	**0**	

Assumptions:

All units will meet Benzene Neshaps Compliance Standards

No COV's will be utilized

AP-42 Factors - Section 5-1 Petroleum Refining 1/95 - Calculations assume 50% control on drains versus uncontrolled drain emissions in AP-42	No. of Units	Units of 1000 liters of flow	Emission Factor Value	Emission Factor Units	Total Emissions (kg/hr)
EMISSION INCREASES					
Drains Controlled	2		0.3	kg/day/unit	0.03
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)	0		0.03	kg/day/unit	0.00
Sealed Manholes	0		0.16	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS	0		0.024	**kg/1000 liters flow**	0.000
Slop oil tanks/OW surge tanks				Use Tanks Program	0.00
OWS Abv Gr (API) Controlled	0		0.024	**kg/1000 liters flow**	0.000
Subtotal for Emission Increases					0.03

EMISSION DECREASES					
Area Drains Controlled			0.3	kg/day/unit	0.00
Area Drains Uncontrolled			0.7	kg/day/unit	0.00
Process Drains Controlled			0.3	kg/day/unit	0.00
Process Drains Uncontrolled			0.7	kg/day/unit	0.00
Catch Basins Controlled			0.3	kg/day/unit	0.00
Catch Basins Uncontrolled			0.7	kg/day/unit	0.00
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)			0.03	kg/day/unit	0.00
Sealed Manholes			0.16	kg/day/unit	0.00
Junction Boxes/Manholes Uncontrolled			0.7	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS (API) Controlled			0.024	kg/1000 liters	0.00
OWS (API) Uncontrolled			0.6	kg/1000 liters	0.00
Slop oil tanks/OW surge tanks					0.00
OWS Abv Gr (API) UnControlled			0.6	kg/1000 liters	0.00
OWS Abv Gr (API) Controlled			0.024	kg/1000 liters	0.00
Subtotal for Emission Decreases					0.00

NET EMISSIONS

kg/hr	0.03
lb/d	1.52
lb/yr	556
TPY	**0.3**

Notes

Emission Source		Units	Source*
Uncontrolled Drain	0.69	Kg/day	AP-42 (e.g. 450/650)
Controlled Drain (with water trap – 50% control of AP-42)	0.0145	Kg/hr	BIDa
Sealed Manway Cover (gasketed – 77% of AP-42)	0.022	Kg/hr	BIDb
Uncontrolled Junction Box (same as an Uncontrolled Drain)	0.029	Kg/hr	AP-42 (ref. BIDa)
Controlled Junction Box (with carbon canister to comply with BWON – 5% of AP-42)	0.00145	Kg/hr	BIDa, BWON
Uncontrolled OWS	0.6	Kg/1000 liters	AP-42
Controlled OWS	0.024	Kg/1000 liters	AP-42

*Notes:
BIDa - Background Information Document to Proposed NSPS QQQ, Feb. 1985.
BIDb - Background Information Document to Proposed NSPS QQQ, Dec. 1987.
AP-42 - AP 42, Fifth Edition, Volume I Chapter 5.1 Petroleum Refining, Jan. 1995.

11B Emergency Relief Valves to the DDU Flare

Note that the work for 11B is associated with the 11C WARP project.

Process			HHV	Sulfur	Frequency	Duration	VOC				NO_X				SO_2				PM				$PM_{10}/PM_{2.5}$				CO				Pb				Hg				Be			
Unit	Malfunction Rates		BTU/scf	ppm	#/year	hours	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/day[1]	tpy	EF	Unit	lb/day[1]	tpy
C-178	0.0056525	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		9.4	0.00	1.9	lb/MMscf	0.01	0.00	7.6	lb/MMscf	0.06	0.00	0.37	lb/MMBtu	2.8	0.00	5.0E-04	lb/MMscf	3.7E-06	1.85E-09	1.84E-04	lb/MMscf	1.4E-06	6.78E-10	1.20E-05	lb/MMscf	8.9E-08	4.43E-11
C-176	0.0056525	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		9.4	0.00	1.9	lb/MMscf	0.01	0.00	7.6	lb/MMscf	0.06	0.00	0.37	lb/MMBtu	2.8	0.00	5.0E-04	lb/MMscf	3.7E-06	1.85E-09	1.84E-04	lb/MMscf	1.4E-06	6.78E-10	1.20E-05	lb/MMscf	8.9E-08	4.43E-11
C-34B	0.0157137	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	1.4	0.00	see below[2]		26.1	0.01	1.9	lb/MMscf	0.04	0.00	7.6	lb/MMscf	0.16	0.00	0.37	lb/MMBtu	7.8	0.00	5.0E-04	lb/MMscf	1.0E-05	5.14E-09	1.84E-04	lb/MMscf	3.8E-06	1.89E-09	1.20E-05	lb/MMscf	2.5E-07	1.23E-10
C-220	0.0381619	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	3.5	0.00	see below[2]		63.4	0.03	1.9	lb/MMscf	0.09	0.00	7.6	lb/MMscf	0.38	0.00	0.37	lb/MMBtu	18.8	0.01	5.0E-04	lb/MMscf	2.5E-05	1.25E-08	1.84E-04	lb/MMscf	9.2E-06	4.58E-09	1.20E-05	lb/MMscf	6.0E-07	2.99E-10
C-199	0.0022759	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		3.8	0.00	1.9	lb/MMscf	0.01	0.00	7.6	lb/MMscf	0.02	0.00	0.37	lb/MMBtu	1.1	0.00	5.0E-04	lb/MMscf	1.5E-06	7.44E-10	1.84E-04	lb/MMscf	5.5E-07	2.73E-10	1.20E-05	lb/MMscf	3.6E-08	1.79E-11
C-191	0.0008182	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		1.4	0.00	1.9	lb/MMscf	0.00	0.00	7.6	lb/MMscf	0.01	0.00	0.37	lb/MMBtu	0.4	0.00	5.0E-04	lb/MMscf	5.3E-07	2.67E-10	1.84E-04	lb/MMscf	2.0E-07	9.82E-11	1.20E-05	lb/MMscf	1.3E-08	6.42E-12
C-194	0.0055694	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		9.3	0.00	1.9	lb/MMscf	0.01	0.00	7.6	lb/MMscf	0.06	0.00	0.37	lb/MMBtu	2.7	0.00	5.0E-04	lb/MMscf	3.6E-06	1.82E-09	1.84E-04	lb/MMscf	1.3E-06	6.68E-10	1.20E-05	lb/MMscf	8.7E-08	4.37E-11
C-192	0.0055694	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		9.3	0.00	1.9	lb/MMscf	0.01	0.00	7.6	lb/MMscf	0.06	0.00	0.37	lb/MMBtu	2.7	0.00	5.0E-04	lb/MMscf	3.6E-06	1.82E-09	1.84E-04	lb/MMscf	1.3E-06	6.68E-10	1.20E-05	lb/MMscf	8.7E-08	4.37E-11
C-174	0.0033694	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.3	0.00	see below[2]		5.6	0.00	1.9	lb/MMscf	0.01	0.00	7.6	lb/MMscf	0.03	0.00	0.37	lb/MMBtu	1.7	0.00	5.0E-04	lb/MMscf	2.2E-06	1.10E-09	1.84E-04	lb/MMscf	8.1E-07	4.04E-10	1.20E-05	lb/MMscf	5.3E-08	2.64E-11
C-206	0.0003182	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.0	0.00	see below[2]		0.5	0.00	1.9	lb/MMscf	0.00	0.00	7.6	lb/MMscf	0.00	0.00	0.37	lb/MMBtu	0.2	0.00	5.0E-04	lb/MMscf	2.1E-07	1.04E-10	1.84E-04	lb/MMscf	7.6E-08	3.82E-11	1.20E-05	lb/MMscf	5.0E-09	2.50E-12
C-204	0.0018602	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		3.1	0.00	1.9	lb/MMscf	0.00	0.00	7.6	lb/MMscf	0.02	0.00	0.37	lb/MMBtu	0.9	0.00	5.0E-04	lb/MMscf	1.2E-06	6.08E-10	1.84E-04	lb/MMscf	4.5E-07	2.23E-10	1.20E-05	lb/MMscf	2.9E-08	1.46E-11
C-122	0.0340966	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	3.1	0.00	see below[2]		56.7	0.03	1.9	lb/MMscf	0.08	0.00	7.6	lb/MMscf	0.34	0.00	0.37	lb/MMBtu	16.8	0.01	5.0E-04	lb/MMscf	2.2E-05	1.11E-08	1.84E-04	lb/MMscf	8.2E-06	4.09E-09	1.20E-05	lb/MMscf	5.3E-07	2.67E-10
C-160	0.0143992	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	1.3	0.00	see below[2]		23.9	0.01	1.9	lb/MMscf	0.04	0.00	7.6	lb/MMscf	0.14	0.00	0.37	lb/MMBtu	7.1	0.00	5.0E-04	lb/MMscf	9.4E-06	4.71E-09	1.84E-04	lb/MMscf	3.5E-06	1.73E-09	1.20E-05	lb/MMscf	2.3E-07	1.13E-10
C-205	0.0346873	MMscfh	4,000	30,000	1.0	0.33					0.068	lb/MMBtu	3.1	0.00	see below[2]		57.6	0.03	1.9	lb/MMscf	0.09	0.00	7.6	lb/MMscf	0.34	0.00	0.37	lb/MMBtu	17.1	0.01	5.0E-04	lb/MMscf	2.3E-05	1.13E-08	1.84E-04	lb/MMscf	8.3E-06	4.16E-09	1.20E-05	lb/MMscf	5.4E-07	2.72E-10

	VOC[3]		NO_X		SO_2		PM		$PM_{10}/PM_{2.5}$		CO		Pb		Hg		Be	
Total Projected Actual Emissions				7.6E-03		0.14		2.1E-04		8.4E-04		0.04		5.5E-08		2.0E-08		1.3E-09
Major New Source Review Thresholds		40		40		40		25		15		100		0.6		0.1		0.1
Major New Source Review Triggered?		No		No		No		No		No		No		No		No		No

[1] Event emission rate represents one worst case emergency/malfunction scenario event. Annual emission rate represents the estimated annual average total duration of worst case emergency/malfunction events.

[2] SO_2 Emissions Calculation:

SO2 MW (lb/lb-mole)=	64

SO2 emissions are calculated based on the concentration of sulfur in the gas stream, the ideal gas law, and the molecular weight of SO2.

General Assumptions Used in Calculations

Variable	Value	Units
V	1,000,000	ft^3
P	14.7	psia
R	10.73	psia-ft^3/lbmol-R
T	527.7	R
md	2596.15	lbmols/MMscf
	385.1851	scf/lbmol

Ideal Gas Law used to determine the moles of gas per MSCF (P*V=n*R*T)

[3] Note that VOC emissions will actually decrease with respect to the current scenario where releases are not vented to the Flare since they will be controlled by the Flare; therefore, the potential VOC emissions associated with emergencies and malfunctions will decrease. Refer to the application text for more information.

Other Notes:

- Natural gas Higher Heating Value (Btu/scf) = 1020
- The 11B WARP project ties existing blowdown RVs to the DDU Flare header system and consists of emergency RVs only. Nitrogen will be used as the purge gas for the new header tie-ins.
- No modifications to the flare, flare knockout drum, or piping from the knockout drum to the flare required modifications to accommodate the worst case emergency relief scenarios when considering the worst case relief scenarios for the current operations
- Regulatory applicability for 40 CFR 63, Subpart CC will not change as a result of the project. Emergency RVs are not miscellaneous process vents per 40 CFR 63, Subpart CC since they are exempted from the definition in 40 CFR 63.641
- RV release gas combustion emission factors for PM/PM10/PM2.5, Lead, Mercury, and Beryllium are from AP-42 Section 1.4 (July 1998). Emission factors for VOC, NOx, and CO are from AP-42 Section 13.5 (September 1991). The emissions for SO2 are calculated
- The HHV and sulfur content was conservatively estimated based on the range of material that could be released. It was also conservatively assumed that each RV would lift one time per year, although this is an unlikely scenario.

11C PS Emergency Relief Valves to the DDU Flare

Process Unit	Malfunction Rates		HHV BTU/scf	Sulfur ppm	Frequency #/year	Duration hours	VOC EF	VOC Unit	VOC lb/event[1]	VOC tpy	NO_x EF	NO_x Unit	NO_x lb/event[1]	NO_x tpy	SO_2 EF	SO_2 Unit	SO_2 lb/event[1]	SO_2 tpy	PM EF	PM Unit	PM lb/event[1]	PM tpy	$PM_{10}/PM_{2.5}$ EF	$PM_{10}/PM_{2.5}$ Unit	$PM_{10}/PM_{2.5}$ lb/event[1]	$PM_{10}/PM_{2.5}$ tpy	CO EF	CO Unit	CO lb/event[1]	CO tpy	Pb EF	Pb Unit	Pb lb/event[1]	Pb tpy	Hg EF	Hg Unit	Hg lb/day[1]	Hg tpy	Be EF	Be Unit	Be lb/day[1]	Be tpy
Z-168	0.0054585	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.9	0.00	5.0E-04	lb/MMscf	1.2E-06	5.80E-10	1.84E-04	lb/MMscf	4.3E-07	2.13E-10	1.20E-05	lb/MMscf	2.8E-08	1.39E-11
Z-203	0.0026753	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.1	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.4	0.00	5.0E-04	lb/MMscf	5.7E-07	2.84E-10	1.84E-04	lb/MMscf	2.1E-07	1.04E-10	1.20E-05	lb/MMscf	1.4E-08	6.82E-12
Z-242	0.0061985	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.0	0.00	5.0E-04	lb/MMscf	1.3E-06	6.58E-10	1.84E-04	lb/MMscf	4.8E-07	2.42E-10	1.20E-05	lb/MMscf	3.2E-08	1.58E-11
Z-154	0.0045804	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.7	0.00	5.0E-04	lb/MMscf	9.7E-07	4.86E-10	1.84E-04	lb/MMscf	3.6E-07	1.79E-10	1.20E-05	lb/MMscf	2.3E-08	1.17E-11
Z-145	0.0102079	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.3	0.00	see below[2]		0.6	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.6	0.00	5.0E-04	lb/MMscf	2.2E-06	1.08E-09	1.84E-04	lb/MMscf	8.0E-07	3.98E-10	1.20E-05	lb/MMscf	5.2E-08	2.60E-11
Z-205	0.0029595	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.2	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.5	0.00	5.0E-04	lb/MMscf	6.3E-07	3.14E-10	1.84E-04	lb/MMscf	2.3E-07	1.15E-10	1.20E-05	lb/MMscf	1.5E-08	7.54E-12
Z-237	0.0029595	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.2	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.5	0.00	5.0E-04	lb/MMscf	6.3E-07	3.14E-10	1.84E-04	lb/MMscf	2.3E-07	1.15E-10	1.20E-05	lb/MMscf	1.5E-08	7.54E-12
Z-140	0.2226303	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	6.6	0.00	see below[2]		12.3	0.01	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	0.7	0.00	0.37	lb/MMBtu	35.7	0.02	5.0E-04	lb/MMscf	4.7E-05	2.36E-08	1.84E-04	lb/MMscf	1.7E-05	8.68E-09	1.20E-05	lb/MMscf	1.1E-06	5.67E-10
Z-218	0.302738	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	8.9	0.00	see below[2]		16.8	0.01	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	1.0	0.00	0.37	lb/MMBtu	48.5	0.02	5.0E-04	lb/MMscf	6.4E-05	3.22E-08	1.84E-04	lb/MMscf	2.4E-05	1.18E-08	1.20E-05	lb/MMscf	1.5E-06	7.72E-10
Z-217	0.0102227	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.3	0.00	see below[2]		0.6	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.6	0.00	5.0E-04	lb/MMscf	2.2E-06	1.09E-09	1.84E-04	lb/MMscf	8.0E-07	3.99E-10	1.20E-05	lb/MMscf	5.2E-08	2.61E-11
Z-216	0.0069113	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.4	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.1	0.00	5.0E-04	lb/MMscf	1.5E-06	7.34E-10	1.84E-04	lb/MMscf	5.4E-07	2.70E-10	1.20E-05	lb/MMscf	3.5E-08	1.76E-11
Z-221	0.0094034	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.3	0.00	see below[2]		0.5	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.5	0.00	5.0E-04	lb/MMscf	2.0E-06	9.99E-10	1.84E-04	lb/MMscf	7.3E-07	3.67E-10	1.20E-05	lb/MMscf	4.8E-08	2.40E-11
Z-207	0.0054217	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.9	0.00	5.0E-04	lb/MMscf	1.2E-06	5.76E-10	1.84E-04	lb/MMscf	4.2E-07	2.11E-10	1.20E-05	lb/MMscf	2.8E-08	1.38E-11
Z-202	0.0045351	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.7	0.00	5.0E-04	lb/MMscf	9.6E-07	4.82E-10	1.84E-04	lb/MMscf	3.5E-07	1.77E-10	1.20E-05	lb/MMscf	2.3E-08	1.16E-11
Z-225	0.007647	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.4	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.2	0.00	5.0E-04	lb/MMscf	1.6E-06	8.12E-10	1.84E-04	lb/MMscf	6.0E-07	2.98E-10	1.20E-05	lb/MMscf	3.9E-08	1.95E-11
Z-204	0.0057253	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.9	0.00	5.0E-04	lb/MMscf	1.2E-06	6.08E-10	1.84E-04	lb/MMscf	4.5E-07	2.23E-10	1.20E-05	lb/MMscf	2.9E-08	1.46E-11
Z-228	0.202389	MMscfh	1,300	400,000	1.0	0.33					0.068	lb/MMBtu	6.0	0.00	see below[2]		4483.7	2.24	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	0.7	0.00	0.37	lb/MMBtu	32.4	0.02	5.0E-04	lb/MMscf	4.3E-05	2.15E-08	1.84E-04	lb/MMscf	1.6E-05	7.89E-09	1.20E-05	lb/MMscf	1.0E-06	5.16E-10
Z-139	0.0091026	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.3	0.00	see below[2]		0.5	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.5	0.00	5.0E-04	lb/MMscf	1.9E-06	9.67E-10	1.84E-04	lb/MMscf	7.1E-07	3.55E-10	1.20E-05	lb/MMscf	4.6E-08	2.32E-11
Z-241	0.0029595	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.2	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.5	0.00	5.0E-04	lb/MMscf	6.3E-07	3.14E-10	1.84E-04	lb/MMscf	2.3E-07	1.15E-10	1.20E-05	lb/MMscf	1.5E-08	7.54E-12
Z-101	0.2560707	MMscfh	1,300	30,000	1.0	0.33					0.068	lb/MMBtu	7.5	0.00	see below[2]		425.5	0.21	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	0.8	0.00	0.37	lb/MMBtu	41.1	0.02	5.0E-04	lb/MMscf	5.4E-05	2.72E-08	1.84E-04	lb/MMscf	2.0E-05	9.99E-09	1.20E-05	lb/MMscf	1.3E-06	6.53E-10
Z-107	0.8227902	MMscfh	4,496	1,000	1.0	0.33					0.068	lb/MMBtu	83.9	0.04	see below[2]		45.6	0.02	1.9	lb/MMscf	2.3	0.00	7.6	lb/MMscf	9.2	0.00	0.37	lb/MMBtu	456.3	0.23	5.0E-04	lb/MMscf	6.0E-04	3.02E-07	1.84E-04	lb/MMscf	2.2E-04	1.11E-07	1.20E-05	lb/MMscf	1.5E-05	7.25E-09
Z-222	0.002347	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.1	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.4	0.00	5.0E-04	lb/MMscf	5.0E-07	2.49E-10	1.84E-04	lb/MMscf	1.8E-07	9.15E-11	1.20E-05	lb/MMscf	1.2E-08	5.98E-12
Z-220	0.0056081	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.9	0.00	5.0E-04	lb/MMscf	1.2E-06	5.96E-10	1.84E-04	lb/MMscf	4.4E-07	2.19E-10	1.20E-05	lb/MMscf	2.9E-08	1.43E-11
Z-114	0.0047881	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.8	0.00	5.0E-04	lb/MMscf	1.0E-06	5.09E-10	1.84E-04	lb/MMscf	3.7E-07	1.87E-10	1.20E-05	lb/MMscf	2.4E-08	1.22E-11
Z-156	0.0036926	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.2	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.6	0.00	5.0E-04	lb/MMscf	7.8E-07	3.92E-10	1.84E-04	lb/MMscf	2.9E-07	1.44E-10	1.20E-05	lb/MMscf	1.9E-08	9.41E-12
Z-116	0.0104647	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.3	0.00	see below[2]		0.6	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	1.7	0.00	5.0E-04	lb/MMscf	2.2E-06	1.11E-09	1.84E-04	lb/MMscf	8.2E-07	4.08E-10	1.20E-05	lb/MMscf	5.3E-08	2.67E-11
Z-134	0.0021965	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.1	0.00	see below[2]		0.1	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.4	0.00	5.0E-04	lb/MMscf	4.7E-07	2.33E-10	1.84E-04	lb/MMscf	1.7E-07	8.57E-11	1.20E-05	lb/MMscf	1.1E-08	5.60E-12
Z-121	0.2713905	MMscfh	5,662	1,000	1.0	0.33					0.068	lb/MMBtu	34.8	0.02	see below[2]		15.0	0.01	1.9	lb/MMscf	1.0	0.00	7.6	lb/MMscf	3.8	0.00	0.37	lb/MMBtu	189.5	0.09	5.0E-04	lb/MMscf	2.5E-04	1.26E-07	1.84E-04	lb/MMscf	9.2E-05	4.61E-08	1.20E-05	lb/MMscf	6.0E-06	3.01E-09
Z-132	0.0054392	MMscfh	1,300	1,000	1.0	0.33					0.068	lb/MMBtu	0.2	0.00	see below[2]		0.3	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	0.9	0.00	5.0E-04	lb/MMscf	1.2E-06	5.78E-10	1.84E-04	lb/MMscf	4.2E-07	2.12E-10	1.20E-05	lb/MMscf	2.8E-08	1.39E-11

	VOC[3]		NO_x		SO_2		PM		$PM_{10}/PM_{2.5}$		CO		Pb		Hg		Be	
Total Projected Actual Emissions				0.08		2.50		0.00		0.01		0.4		5.5E-07		2.0E-07		1.3E-08
Major New Source Review Thresholds		40		40		40		25		15		100		0.6		0.1		0.1
Major New Source Review Triggered?		N		No		No		No		No		No		No		No		No

[1] Event emission rate represents one worst case emergency/malfunction scenario event. Annual emission rate represents the estimated annual average total duration of worst case emergency/malfunction events.

[2] SO_2 Emissions Calculation:

SO2 MW (lb/lb-mole)=	64

SO2 emissions are calculated based on the concentration of sulfur in the gas stream, the ideal gas law, and the molecular weight of SO2.

General Assumptions Used in Calculations

Variable	Value	Units
V	1,000,000	ft^3
P	14.7	psia
R	10.73	psia-ft^3/lbmol-R
T	527.7	R
md	2596.15	lbmols/MMscf
	385.1851	scf/lbmol

Ideal Gas Law used to determine the moles of gas per MSCF (P*V=n*R*T)

[3] Note that VOC emissions will actually decrease with respect to the current scenario where releases are not vented to the Flare since they will be controlled by the Flare; therefore, the potential VOC emissions associated with emergencies and malfunction

Other Notes:

- Natural gas Higher Heating Value (Btu/scf) = 1020
- The 11C WARP project ties existing blowdown RVs to the DDU Flare header system and consists of emergency RVs only. Nitrogen will be used as the purge gas for the new header tie-ins.
- No modifications to the flare, flare knockout drum, or piping from the knockout drum to the flare required modifications to accommodate the worst case emergency relief scenarios when considering the worst case relief scenarios for the current operations
- Regulatory applicability for 40 CFR 63, Subpart CC will not change as a result of the project. Emergency RVs are not miscellaneous process vents per 40 CFR 63, Subpart CC since they are exempted from the definition in 40 CFR 63.641
- RV release gas combustion emission factors for PM/PM10/PM2.5, Lead, and Mercury are from AP-42 Section 1.4 (July 1998). Emission factors for VOC, NOx, and CO are from AP-42 Section 13.5 (September 1991). The emissions for SO2 are calculated by assumin
- The HHV and sulfur content was conservatively estimated based on the range of material that could be released. It was also conservatively assumed that each RV would lift one time per year, although this is an unlikely scenario.

Fugitive Emission Calculations for WARP at FCU500

Refer to application text for more information regarding FCU 500 WARP and these estimated component counts.

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	93	0.1878	0.0037	2.0%	0.6865	95%	100%	0.15
Heavy Liquid	4	0.00051	0.00051	2.0%	0.0020	30%	100%	0.01
Pumps								
Light Liquid	1	0.9630	0.0265	2.0%	0.0452	80%	100%	0.04
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	1	0.0827	0.00013	0.3%	0.0004	30%	100%	0.00
Light Liquid	192	0.0827	0.00013	0.3%	0.0725	30%	100%	0.22
Heavy Liquid	11	0.0827	0.00013	0.3%	0.0042	30%	100%	0.01
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.43**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Increased Sewer Emissions from FCU500 WARP Project due to Added Equipment

EQUIPMENT TYPE	UNIT FCU500 - Estimated Counts	
Atmospheric Drain Hub	4	
Catch Basin (Pad or Paving Drain)	0	
Inspection Points	0	
Cleanouts	0	
Above Ground Sewer Pump Out Points		
Sum of Drains	**4**	*Does Not include Above ground pump out lines as are typically fugitive emissions included with fugitives*
Manhole/Junction Box w/o Vent		
Manhole/Junction Box w/ CC and/or Vent		
OSBL Manholes Per Unit - Sealed		
Flare / Degassing/ KO Tanks (ie Above Ground Junction Boxes)	0	
Sealed cover sumps - Gas Traps or other sumps		
Total Manholes/Junction Boxes/Sealed Sumps	**0**	
Below Grade Oily Water Separator - Fixed Roof		
Below Grade Oily Water Separator - Floating Roof		
OSBL Sumps/OWS Per Unit		
Total In ground OWS/Sumps	**0**	
Tanks DGO / LGO / Sour Water service		
Above Ground Oil Water Separator Tanks		
Total Above Ground Tanks	**0**	

Assumptions:

All units will meet Benzene Neshaps Compliance Standards

No COV's will be utilized

AP-42 Factors - Section 5-1 Petroleum Refining 1/95 - Calculations assume 50% control on drains versus uncontrolled drain emissions in AP-42	No. of Units	Units of 1000 liters of flow	Emission Factor Value	Emission Factor Units	Total Emissions (kg/hr)
EMISSION INCREASES					
Drains Controlled	4		0.3	kg/day/unit	0.06
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)	0		0.03	kg/day/unit	0.00
Sealed Manholes	0		0.16	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS	0		0.024	**kg/1000 liters flow**	0.000
Slop oil tanks/OW surge tanks				Use Tanks Program	0.00
OWS Abv Gr (API) Controlled	0		0.024	**kg/1000 liters flow**	0.000
Subtotal for Emission Increases					0.06

EMISSION DECREASES					
Area Drains Controlled			0.3	kg/day/unit	0.00
Area Drains Uncontrolled			0.7	kg/day/unit	0.00
Process Drains Controlled			0.3	kg/day/unit	0.00
Process Drains Uncontrolled			0.7	kg/day/unit	0.00
Catch Basins Controlled			0.3	kg/day/unit	0.00
Catch Basins Uncontrolled			0.7	kg/day/unit	0.00
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)			0.03	kg/day/unit	0.00
Sealed Manholes			0.16	kg/day/unit	0.00
Junction Boxes/Manholes Uncontrolled			0.7	kg/day/unit	0.00
Oil Water Separator and Auxillaries					
OWS (API) Controlled			0.024	kg/1000 liters	0.00
OWS (API) Uncontrolled			0.6	kg/1000 liters	0.00
Slop oil tanks/OW surge tanks					0.00
OWS Abv Gr (API) UnControlled			0.024	kg/1000 liters	0.00
OWS Abv Gr (API) Controlled			0.6	kg/1000 liters	0.00
Subtotal for Emission Decreases					0.00

NET EMISSIONS

kg/hr	0.06
lb/d	3.05
lb/yr	1112
TPY	**0.6**

Notes:

Emission Source		Units	Source*
Uncontrolled Drain	0.69	Kg/day	AP-42 (e.g. 450/650)
Controlled Drain (with water trap – 50% control of AP-42)	0.0145	Kg/hr	BIDa
Sealed Manway Cover (gasketed – 77% of AP-42)	0.022	Kg/hr	BIDb
Uncontrolled Junction Box (same as an Uncontrolled Drain)	0.029	Kg/hr	AP-42 (ref. BIDa)
Controlled Junction Box (with carbon canister to comply with BWON – 5% of AP-42)	0.00145	Kg/hr	BIDa, BWON
Uncontrolled OWS	0.6	Kg/1000 liters	AP-42
Controlled OWS	0.024	Kg/1000 liters	AP-42

*Notes:

BIDa - Background Information Document to Proposed NSPS QQQ, Feb. 1985.

BIDb - Background Information Document to Proposed NSPS QQQ, Dec. 1987.

AP-42 - AP 42, Fifth Edition, Volume I Chapter 5.1 Petroleum Refining, Jan. 1995.

Fugitive Emission Calculations for WARP at FCU 600

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	93	0.1878	0.0037	2.0%	0.6865	95%	100%	0.15
Heavy Liquid	4	0.00051	0.00051	2.0%	0.0020	30%	100%	0.01
Pumps								
Light Liquid	1	0.9630	0.0265	2.0%	0.0452	80%	100%	0.04
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	1	0.0827	0.00013	0.3%	0.0004	30%	100%	0.00
Light Liquid	192	0.0827	0.00013	0.3%	0.0725	30%	100%	0.22
Heavy Liquid	11	0.0827	0.00013	0.3%	0.0042	30%	100%	0.01
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves - Added[3]	0	3.728	0.0985	2.0%	0.0000	98%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
Total VOC Emissions Associated with Added Components (tons/yr):								0.43

Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	-15	0.1878	0.0037	2.0%	-0.1107	95%	100%	-0.02
Heavy Liquid	-2	0.00051	0.00051	2.0%	-0.0010	30%	100%	0.00
Flanges								
Gas/Vapor	-6	0.0827	0.00013	0.3%	-0.0023	30%	100%	-0.01
Light Liquid	-22	0.0827	0.00013	0.3%	-0.0083	30%	100%	-0.03
Heavy Liquid	-7	0.0827	0.00013	0.3%	-0.0026	30%	100%	-0.01
Total VOC Emissions Associated with Removed Components (tons/yr):								**-0.07**

Past Emissions from Relief Valves - Existing Controlled[3]	41	3.728	0.0985	2.0%	7.0147	90%	100%	3.07
Relief Valves - Existing Controlled[3]	41	3.728	0.0985	2.0%	7.0147	98%	100%	0.61
Emissions Reduction (Future - Past)								-2.46
Total VOC Emissions Associated with Added Components and Additional Controls (tons/yr):								**-2.09**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

[3] There are no new relief valves and 41 existing RV's - previously routed to the atmosphere (through the blowdown stack) that are now routed to the FCU flare. The existing RVs were previously controlled with a water spray chamber that is presumed to be capable of 90% control.

Increased Sewer Emissions from FCU600 WARP Project due to Added Equipment

EQUIPMENT TYPE	UNIT FCU600 - Estimated Counts	
Atmospheric Drain Hub	4	
Catch Basin (Pad or Paving Drain)	0	
Inspection Points	0	
Cleanouts	0	
Above Ground Sewer Pump Out Points		
Sum of Drains	**4**	*Does Not include Above ground pump out lines as are typically fugitive emissions included with fugitives*
Manhole/Junction Box w/o Vent		
Manhole/Junction Box w/ CC and/or Vent	1	
OSBL Manholes Per Unit - Sealed		
Flare / Degassing/ KO Tanks (ie Above Ground Junction Boxes)	0	
Sealed cover sumps - Gas Traps or other sumps		
Total Manholes/Junction Boxes/Sealed Sumps	**1**	
Below Grade Oily Water Separator - Fixed Roof		
Below Grade Oily Water Separator - Floating Roof		
OSBL Sumps/OWS Per Unit		
Total In ground OWS/Sumps	**0**	
Tanks DGO / LGO / Sour Water service		
Above Ground Oil Water Separator Tanks		
Total Above Ground Tanks	**0**	

Assumptions:
All units will meet Benzene Neshaps Compliance Standards
No COV's will be utilized

AP-42 Factors - Section 5-1 Petroleum Refining 1/95 - Calculations assume 50% control or drains versus uncontrolled drain emissions in AP-42		No. of Units	Units of 1000 liters of flow	Emission Factor Value	Emission Factor Units	Total Emissions (kg/hr)
EMISSION INCREASES						
Drains Controlled		4		0.3	kg/day/unit	0.06
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)		0		0.03	kg/day/unit	0.00
Sealed Manholes		0		0.16	kg/day/unit	0.00
Oil Water Separator and Auxillaries						
	OWS	0		0.024	**kg/1000 liters flow**	0.000
	Slop oil tanks/OW surge tanks				Use Tanks Program	0.00
	OWS Abv Gr (API) Controlled	0		0.024	**kg/1000 liters flow**	0.000
Subtotal for Emission Increases						0.06

EMISSION DECREASES						
Area Drains Controlled				0.3	kg/day/unit	0.00
Area Drains Uncontrolled				0.7	kg/day/unit	0.00
Process Drains Controlled				0.3	kg/day/unit	0.00
Process Drains Uncontrolled				0.7	kg/day/unit	0.00
Catch Basins Controlled				0.3	kg/day/unit	0.00
Catch Basins Uncontrolled				0.7	kg/day/unit	0.00
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)				0.03	kg/day/unit	0.00
Sealed Manholes				0.16	kg/day/unit	0.00
Junction Boxes/Manholes Uncontrolled				0.7	kg/day/unit	0.00
Oil Water Separator and Auxillaries						
	OWS (API) Controlled			0.024	kg/1000 liters	0.00
	OWS (API) Uncontrolled			0.6	kg/1000 liters	0.00
	Slop oil tanks/OW surge tanks					0.00
	OWS Abv Gr (API) UnControlled			0.024	kg/1000 liters	0.00
	OWS Abv Gr (API) Controlled			0.6	kg/1000 liters	0.00
Subtotal for Emission Decreases						0.00

NET EMISSIONS

kg/hr	0.06
lb/d	3.05
lb/yr	1112
TPY	**0.6**

Notes:

Emission Source		Units	Source*
Uncontrolled Drain	0.69	Kg/day	AP-42 (e.g. 450/650)
Controlled Drain (with water trap – 50% control of AP-42)	0.0145	Kg/hr	BIDa
Sealed Manway Cover (gasketed – 77% of AP-42)	0.022	Kg/hr	BIDb
Uncontrolled Junction Box (same as an Uncontrolled Drain)	0.029	Kg/hr	AP-42 (ref. BIDa)
Controlled Junction Box (with carbon canister to comply with BWON – 5% of AP-42)	0.00145	Kg/hr	BIDa, BWON
Uncontrolled OWS	0.6	Kg/1000 liters	AP-42
Controlled OWS	0.024	Kg/1000 liters	AP-42

*Notes:

BIDa - Background Information Document to Proposed NSPS QQQ, Feb. 1985.

BIDb - Background Information Document to Proposed NSPS QQQ, Dec. 1987.

AP-42 - AP 42, Fifth Edition, Volume I Chapter 5.1 Petroleum Refining, Jan. 1995.

FCU 600 Emergency Relief Valves to the FCU Flare

RV's	Malfunction Rates		HHV	Sulfur	Frequency	Duration	VOC				NO_X				SO_2				PM				$PM_{10}/PM_{2.5}$				CO				Pb				Hg				Be			
			BTU/scf	ppm	#/year	hours	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/event[1]	tpy	EF	Unit	lb/day[1]	tpy	EF	Unit	lb/day[1]	tpy
R-0041	1.33E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.9	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.4	0.00	5.0E-04	lb/MMscf	3.2E-06	1.59E-09	1.84E-04	lb/MMscf	1.2E-06	5.85E-10	1.20E-05	lb/MMscf	7.6E-08	3.82E-11
R-0045	1.33E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.9	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.4	0.00	5.0E-04	lb/MMscf	3.2E-06	1.59E-09	1.84E-04	lb/MMscf	1.2E-06	5.85E-10	1.20E-05	lb/MMscf	7.6E-08	3.82E-11
R-0049	1.33E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.9	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.4	0.00	5.0E-04	lb/MMscf	3.2E-06	1.59E-09	1.84E-04	lb/MMscf	1.2E-06	5.85E-10	1.20E-05	lb/MMscf	7.6E-08	3.82E-11
R-0047	1.33E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.9	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.4	0.00	5.0E-04	lb/MMscf	3.2E-06	1.59E-09	1.84E-04	lb/MMscf	1.2E-06	5.85E-10	1.20E-05	lb/MMscf	7.6E-08	3.82E-11
R-0048	1.33E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.9	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.4	0.00	5.0E-04	lb/MMscf	3.2E-06	1.59E-09	1.84E-04	lb/MMscf	1.2E-06	5.85E-10	1.20E-05	lb/MMscf	7.6E-08	3.82E-11
R-0051	1.33E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.9	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.4	0.00	5.0E-04	lb/MMscf	3.2E-06	1.59E-09	1.84E-04	lb/MMscf	1.2E-06	5.85E-10	1.20E-05	lb/MMscf	7.6E-08	3.82E-11
R-2099	2.52E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.8	0.00	see below[2]		1.7	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	4.5	0.00	5.0E-04	lb/MMscf	6.0E-06	3.01E-09	1.84E-04	lb/MMscf	2.2E-06	1.10E-09	1.20E-05	lb/MMscf	1.4E-07	7.22E-11
R-2100	2.52E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.8	0.00	see below[2]		1.7	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	4.5	0.00	5.0E-04	lb/MMscf	6.0E-06	3.01E-09	1.84E-04	lb/MMscf	2.2E-06	1.10E-09	1.20E-05	lb/MMscf	1.4E-07	7.22E-11
R-2010	2.74E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.9	0.00	see below[2]		1.8	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	4.9	0.00	5.0E-04	lb/MMscf	6.5E-06	3.27E-09	1.84E-04	lb/MMscf	2.4E-06	1.20E-09	1.20E-05	lb/MMscf	1.6E-07	7.85E-11
R-2011	2.74E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.9	0.00	see below[2]		1.8	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	4.9	0.00	5.0E-04	lb/MMscf	6.5E-06	3.27E-09	1.84E-04	lb/MMscf	2.4E-06	1.20E-09	1.20E-05	lb/MMscf	1.6E-07	7.85E-11
R-2107	2.26E-03	MMscfh	12,338	11,000	1	0.33					0.068	lb/MMBtu	0.6	0.00	see below[2]		1.4	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	3.4	0.00	5.0E-04	lb/MMscf	4.5E-06	2.27E-09	1.84E-04	lb/MMscf	1.7E-06	8.35E-10	1.20E-05	lb/MMscf	1.1E-07	5.46E-11
R-2108	2.26E-03	MMscfh	12,338	11,000	1	0.33					0.068	lb/MMBtu	0.6	0.00	see below[2]		1.4	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	3.4	0.00	5.0E-04	lb/MMscf	4.5E-06	2.27E-09	1.84E-04	lb/MMscf	1.7E-06	8.35E-10	1.20E-05	lb/MMscf	1.1E-07	5.46E-11
R-2069	2.72E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.6	0.00	see below[2]		1.1	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	3.3	0.00	5.0E-04	lb/MMscf	4.4E-06	2.19E-09	1.84E-04	lb/MMscf	1.6E-06	8.05E-10	1.20E-05	lb/MMscf	1.1E-07	5.26E-11
R-2054	2.72E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.6	0.00	see below[2]		1.1	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	3.3	0.00	5.0E-04	lb/MMscf	4.4E-06	2.19E-09	1.84E-04	lb/MMscf	1.6E-06	8.05E-10	1.20E-05	lb/MMscf	1.1E-07	5.26E-11
R-2055	4.09E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.9	0.00	see below[2]		1.6	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	5.0	0.00	5.0E-04	lb/MMscf	6.6E-06	3.30E-09	1.84E-04	lb/MMscf	2.4E-06	1.21E-09	1.20E-05	lb/MMscf	1.6E-07	7.91E-11
R-2004	2.76E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.6	0.00	see below[2]		1.1	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	3.4	0.00	5.0E-04	lb/MMscf	4.4E-06	2.22E-09	1.84E-04	lb/MMscf	1.6E-06	8.17E-10	1.20E-05	lb/MMscf	1.1E-07	5.34E-11
R-2007	1.47E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		1.0	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	2.7	0.00	5.0E-04	lb/MMscf	3.5E-06	1.76E-09	1.84E-04	lb/MMscf	1.3E-06	6.46E-10	1.20E-05	lb/MMscf	8.4E-08	4.22E-11
R-2020	2.65E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.6	0.00	see below[2]		1.0	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	3.2	0.00	5.0E-04	lb/MMscf	4.3E-06	2.14E-09	1.84E-04	lb/MMscf	1.6E-06	7.86E-10	1.20E-05	lb/MMscf	1.0E-07	5.13E-11
R-2053	1.18E-03	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	0.4	0.00	see below[2]		0.8	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.0	0.00	0.37	lb/MMBtu	2.1	0.00	5.0E-04	lb/MMscf	2.8E-06	1.40E-09	1.84E-04	lb/MMscf	1.0E-06	5.16E-10	1.20E-05	lb/MMscf	6.7E-08	3.37E-11
R-2070	3.48E-02	MMscfh	12,338	11,000	1	0.33					0.068	lb/MMBtu	9.7	0.00	see below[2]		21.2	0.01	1.9	lb/MMscf	0.3	0.00	7.6	lb/MMscf	1.1	0.00	0.37	lb/MMBtu	52.9	0.03	5.0E-04	lb/MMscf	7.0E-05	3.50E-08	1.84E-04	lb/MMscf	2.6E-05	1.29E-08	1.20E-05	lb/MMscf	1.7E-06	8.41E-10
R-2101	3.57E-02	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	8.0	0.00	see below[2]		13.8	0.01	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	0.9	0.00	0.37	lb/MMBtu	43.5	0.02	5.0E-04	lb/MMscf	5.8E-05	2.88E-08	1.84E-04	lb/MMscf	2.1E-05	1.06E-08	1.20E-05	lb/MMscf	1.4E-06	6.92E-10
R-1023	3.98E-02	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	8.9	0.00	see below[2]		15.4	0.01	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	1.0	0.00	0.37	lb/MMBtu	48.5	0.02	5.0E-04	lb/MMscf	6.4E-05	3.22E-08	1.84E-04	lb/MMscf	2.4E-05	1.18E-08	1.20E-05	lb/MMscf	1.5E-06	7.72E-10
R-0920	1.33E-02	MMscfh	14,626	12,000	1	0.33					0.068	lb/MMBtu	4.4	0.00	see below[2]		8.9	0.00	1.9	lb/MMscf	0.1	0.00	7.6	lb/MMscf	0.5	0.00	0.37	lb/MMBtu	24.1	0.01	5.0E-04	lb/MMscf	3.2E-05	1.59E-08	1.84E-04	lb/MMscf	1.2E-05	5.85E-09	1.20E-05	lb/MMscf	7.7E-07	3.83E-10
R-2092	2.66E-02	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	6.0	0.00	see below[2]		10.3	0.01	1.9	lb/MMscf	0.2	0.00	7.6	lb/MMscf	0.7	0.00	0.37	lb/MMBtu	32.5	0.02	5.0E-04	lb/MMscf	4.3E-05	2.15E-08	1.84E-04	lb/MMscf	1.6E-05	7.90E-09	1.20E-05	lb/MMscf	1.0E-06	5.16E-10
R-0926	2.05E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		0.8	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	2.5	0.00	5.0E-04	lb/MMscf	3.3E-06	1.66E-09	1.84E-04	lb/MMscf	1.2E-06	6.08E-10	1.20E-05	lb/MMscf	8.0E-08	3.98E-11
R-0928	2.05E-03	MMscfh	9,880	7,000	1	0.33					0.068	lb/MMBtu	0.5	0.00	see below[2]		0.8	0.00	1.9	lb/MMscf	0.0	0.00	7.6	lb/MMscf	0.1	0.00	0.37	lb/MMBtu	2.5	0.00	5.0E-04	lb/MMscf	3.3E-06	1.66E-09	1.84E-04	lb/MMscf	1.2E-06	6.08E-10	1.20E-05	lb/MMscf	8.0E-08	3.98E-11

	VOC[3]		NO_X		SO_2		PM		$PM_{10}/PM_{2.5}$		CO		Pb		Hg		Be	
Total Projected Actual Emissions				0.02		0.05		6.8E-04		2.7E-03		0.1		1.8E-07		6.6E-08		4.3E-09
Major New Source Review Thresholds		40		40		40		25		15		100		0.6		0.1		0.1
Major New Source Review Triggered?		No		No		No		No		No		No		No		No		No

[1] Event emission rate represents one worst case emergency/malfunction scenario event. Annual emission rate represents the estimated annual average total duration of worst case emergency/malfunction events.

[2] SO_2 Emissions Calculation:

SO2 MW (lb/lb-mole)=		64

SO2 emissions are calculated based on the concentration of sulfur in the gas stream, the ideal gas law, and the molecular weight of SO2.

General Assumptions Used in Calculations

Variable	Value	Units
V	1,000,000	ft^3
P	14.7	psia
R	10.73	psia-ft^3/lbmol-R
T	527.7	R
md	2596.15	lbmols/MMscf
	385.1851	scf/lbmol

Ideal Gas Law used to determine the moles of gas per MSCF (P*V=n*R*T)

[3] Note that VOC emissions will actually decrease with respect to the current scenario where releases are not vented to the Flare since they will be controlled by the Flare; therefore, the potential VOC emissions associated with emergencies and malfunctions will decrease. Refer to the application text for more information.

Other Notes:

- Natural gas Higher Heating Value (Btu/sct) = 1020
- The FCU 600 WARP project ties existing blowdown RVs to the FCU Flare header system and consists of emergency RVs only. Nitrogen will be used as the purge gas for the new header tie-ins.
- No modifications to the flare, flare knockout drum, or piping from the knockout drum to the flare required modifications to accommodate the worst case emergency relief scenarios when considering the worst case relief scenarios for the current operations
- Regulatory applicability for 40 CFR 63, Subpart CC will not change as a result of the project. Emergency RVs are not miscellaneous process vents per 40 CFR 63, Subpart CC since they are exempted from the definition in 40 CFR 63.641
- RV release gas combustion emission factors for PM/PM10/PM2.5, Lead, Beryllium, and Mercury are from AP-42 Section 1.4 (July 1998). Emission factors for VOC, NOx, and CO are from AP-42 Section 13.5 (September 1991). The emissions for SO2 are calculated

Fugitive Emission Calculations for FCU600 TAR

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	10	0.5789	0.0013	2.0%	0.1285	95%	100%	0.03
Light Liquid	26	0.1878	0.0037	2.0%	0.1919	95%	100%	0.04
Heavy Liquid	24	0.00051	0.00051	2.0%	0.0122	30%	100%	0.04
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	26	0.0827	0.00013	0.3%	0.0098	30%	100%	0.03
Light Liquid	78	0.0827	0.00013	0.3%	0.0295	30%	100%	0.09
Heavy Liquid	63	0.0827	0.00013	0.3%	0.0238	30%	100%	0.07
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.30**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Fugitive Emission Calculations for WARP at VRU 100

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	1	0.5789	0.0013	2.0%	0.0129	95%	100%	0.00
Light Liquid	15	0.1878	0.0037	2.0%	0.1107	95%	100%	0.02
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	11	0.0827	0.00013	0.3%	0.0042	30%	100%	0.01
Light Liquid	30	0.0827	0.00013	0.3%	0.0113	30%	100%	0.03
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves - Added[3]	0	3.728	0.0985	2.0%	0.0000	98%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
Total VOC Emissions Associated with Added Components (tons/yr):								0.07

Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	-5	0.1878	0.0037	2.0%	-0.0369	95%	100%	-0.01
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	-16	0.0827	0.00013	0.3%	-0.0060	30%	100%	-0.02
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Total VOC Emissions Associated with Removed Components (tons/yr):								**-0.03**

Past Emissions from Relief Valves - Existing Controlled[3]	2	3.728	0.0985	2.0%	0.3422	90%	100%	0.15
Relief Valves - Existing Controlled[3]	2	3.728	0.0985	2.0%	0.3422	98%	100%	0.03
Emissions Reduction (Future - Past)								-0.12
Total VOC Emissions Associated with Added Components and Additional Controls (tons/yr):								**-0.07**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

[3] There are no new relief valves and 2existing RV's - previously routed to the atmosphere (through the blowdown stack) that are now routed to the VRU flare. The existing RVs were previously controlled with a water spray chamber that is presumed to be capable of 90% control.

Fugitive Emission Calculations for WARP at VRU 200

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	1	0.5789	0.0013	2.0%	0.0129	95%	100%	0.00
Light Liquid	3	0.1878	0.0037	2.0%	0.0221	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	7	0.0827	0.00013	0.3%	0.0026	30%	100%	0.01
Light Liquid	7	0.0827	0.00013	0.3%	0.0026	30%	100%	0.01
Heavy Liquid	1	0.0827	0.00013	0.3%	0.0004	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves - Added[3]	0	3.728	0.0985	2.0%	0.0000	98%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
Total VOC Emissions Associated with Added Components (tons/yr):								0.03

Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	-3	0.1878	0.0037	2.0%	-0.0221	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	-5	0.0827	0.00013	0.3%	-0.0019	30%	100%	-0.01
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Total VOC Emissions Associated with Removed Components (tons/yr):								**-0.01**

Past Emissions from Relief Valves - Existing Controlled[3]	4	3.728	0.0985	2.0%	0.6844	90%	100%	0.30
Relief Valves - Existing Controlled[3]	4	3.728	0.0985	2.0%	0.6844	98%	100%	0.06
Emissions Reduction (Future - Past)								-0.24
Total VOC Emissions Associated with Added Components and Additional Controls (tons/yr):								**-0.23**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

[3] There are no new relief valves and 4 existing RV's - previously routed to the atmosphere (through the blowdown stack) that are now routed to the VRU flare. The existing RVs were previously controlled with a water spray chamber that is presumed to be capable of 90% control.

Increased Sewer Emissions from VRU 100/200 WARP Project due to Added Equipment

EQUIPMENT TYPE	UNIT VRU 100/200 - Estimated Counts	
Atmospheric Drain Hub	1	
Catch Basin (Pad or Paving Drain)	0	
Inspection Points	0	
Cleanouts	0	
Above Ground Sewer Pump Out Points		
Sum of Drains	**1**	*Does Not include Above ground pump out lines as are typically fugitive emissions included with fugitives*
Manhole/Junction Box w/o Vent		
Manhole/Junction Box w/ CC and/or Vent		
OSBL Manholes Per Unit - Sealed		
Flare / Degassing/ KO Tanks (ie Above Ground Junction Boxes)	0	
Sealed cover sumps - Gas Traps or other sumps		
Total Manholes/Junction Boxes/Sealed Sumps	**0**	
Below Grade Oily Water Separator - Fixed Roof		
Below Grade Oily Water Separator - Floating Roof		
OSBL Sumps/OWS Per Unit		
Total In ground OWS/Sumps	**0**	
Tanks DGO / LGO / Sour Water service		
Above Ground Oil Water Separator Tanks		
Total Above Ground Tanks	**0**	

Assumptions:

All units will meet Benzene Neshaps Compliance Standards

No COV's will be utilized

AP-42 Factors - Section 5-1 Petroleum Refining 1/95 - Calculations assume 50% control or drains versus uncontrolled drain emissions in AP-42		No. of Units	Units of 1000 liters of flow	Emission Factor Value	Emission Factor Units	Total Emissions (kg/hr)
EMISSION INCREASES						
Drains Controlled		1		0.3	kg/day/unit	0.01
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)		0		0.03	kg/day/unit	0.00
Sealed Manholes		0		0.16	kg/day/unit	0.00
Oil Water Separator and Auxillaries						
	OWS	0		0.024	**kg/1000 liters flow**	0.000
	Slop oil tanks/OW surge tanks				Use Tanks Program	0.00
	OWS Abv Gr (API) Controlled	0		0.024	**kg/1000 liters flow**	0.000
Subtotal for Emission Increases						0.01

EMISSION DECREASES						
Area Drains Controlled				0.3	kg/day/unit	0.00
Area Drains Uncontrolled				0.7	kg/day/unit	0.00
Process Drains Controlled				0.3	kg/day/unit	0.00
Process Drains Uncontrolled				0.7	kg/day/unit	0.00
Catch Basins Controlled				0.3	kg/day/unit	0.00
Catch Basins Uncontrolled				0.7	kg/day/unit	0.00
Junction Boxes/Manholes Controlled (Carbon Canister to comply with BWON)				0.03	kg/day/unit	0.00
Sealed Manholes				0.16	kg/day/unit	0.00
Junction Boxes/Manholes Uncontrolled				0.7	kg/day/unit	0.00
Oil Water Separator and Auxillaries						
	OWS (API) Controlled			0.024	kg/1000 liters	0.00
	OWS (API) Uncontrolled			0.6	kg/1000 liters	0.00
	Slop oil tanks/OW surge tanks					0.00
	OWS Abv Gr (API) UnControlled			0.024	kg/1000 liters	0.00
	OWS Abv Gr (API) Controlled			0.6	kg/1000 liters	0.00
Subtotal for Emission Decreases						0.00

NET EMISSIONS

kg/hr	0.01
lb/d	0.76
lb/yr	278
TPY	**0.1**

Notes:

Emission Source		Units	Source*
Uncontrolled Drain	0.69230769	Kg/day	AP-42 (e.g. 450/650)
Controlled Drain (with water trap – 50% control of AP-42)	0.0145	Kg/hr	BIDa
Sealed Manway Cover (gasketed – 77% of AP-42)	0.022	Kg/hr	BIDb
Uncontrolled Junction Box (same as an Uncontrolled Drain)	0.029	Kg/hr	AP-42 (ref. BIDa)
Controlled Junction Box (with carbon canister to comply with BWON – 5% of AP-42)	0.00145	Kg/hr	BIDa, BWON
Uncontrolled OWS	0.6	Kg/1000 liters	AP-42
Controlled OWS	0.024	Kg/1000 liters	AP-42

*Notes:
BIDa - Background Information Document to Proposed NSPS QQQ, Feb. 1985.
BIDb - Background Information Document to Proposed NSPS QQQ, Dec. 1987.
AP-42 - AP 42, Fifth Edition, Volume I Chapter 5.1 Petroleum Refining, Jan. 1995.

VRU 100 and VRU 200 Emergency Relief Valves to the VRU Flare

Process Unit	Malfunction Rates		HHV BTU/scf	Sulfur ppm	Frequency #/year	Duration hours	VOC EF	VOC Unit	VOC lb/event[1]	VOC tpy	NO_X EF	NO_X Unit	NO_X lb/event[1]	NO_X tpy	SO_2 EF	SO_2 Unit	SO_2 lb/event[1]	SO_2 tpy	PM EF	PM Unit	PM lb/event[1]	PM tpy	$PM_{10}/PM_{2.5}$ EF	$PM_{10}/PM_{2.5}$ Unit	$PM_{10}/PM_{2.5}$ lb/event[1]	$PM_{10}/PM_{2.5}$ tpy	CO EF	CO Unit	CO lb/event[1]	CO tpy	Pb EF	Pb Unit	Pb lb/event[1]	Pb tpy	Hg EF	Hg Unit	Hg lb/day[1]	Hg tpy	Be EF	Be Unit	Be lb/day[1]	Be tpy
SV-963	0.00326	MMscfh	12,338	11,000	1.0	0.33					0.068	lb/MMBtu	0.9	0.00	see below[2]		2.0	0.00	1.9	lb/MMscf	0.02	0.00	7.6	lb/MMscf	0.10	0.00	0.37	lb/MMBtu	5.0	0.00	5.0E-04	lb/MMscf	6.6E-06	3.29E-09	1.84E-04	lb/MMscf	2.4E-06	1.21E-09	1.20E-05	lb/MMscf	1.6E-07	7.89E-11
SV-972	0.00660	MMscfh	9,880	7,000	1.0	0.33					0.068	lb/MMBtu	1.5	0.00	see below[2]		2.6	0.00	1.9	lb/MMscf	0.04	0.00	7.6	lb/MMscf	0.16	0.00	0.37	lb/MMBtu	8.0	0.00	5.0E-04	lb/MMscf	1.1E-05	5.33E-09	1.84E-04	lb/MMscf	3.9E-06	1.96E-09	1.20E-05	lb/MMscf	2.6E-07	1.28E-10
T-519	0.01424	MMscfh	9,880	7,000	1.0	0.33					0.068	lb/MMBtu	3.2	0.00	see below[2]		5.5	0.00	1.9	lb/MMscf	0.09	0.00	7.6	lb/MMscf	0.35	0.00	0.37	lb/MMBtu	17.3	0.01	5.0E-04	lb/MMscf	2.3E-05	1.15E-08	1.84E-04	lb/MMscf	8.4E-06	4.22E-09	1.20E-05	lb/MMscf	5.5E-07	2.76E-10
T-528	0.00467	MMscfh	9,880	7,000	1.0	0.33					0.068	lb/MMBtu	1.0	0.00	see below[2]		1.8	0.00	1.9	lb/MMscf	0.03	0.00	7.6	lb/MMscf	0.11	0.00	0.37	lb/MMBtu	5.7	0.00	5.0E-04	lb/MMscf	7.5E-06	3.77E-09	1.84E-04	lb/MMscf	2.8E-06	1.38E-09	1.20E-05	lb/MMscf	1.8E-07	9.05E-11
T-526	0.00242	MMscfh	12,338	11,000	1.0	0.33					0.068	lb/MMBtu	0.7	0.00	see below[2]		1.5	0.00	1.9	lb/MMscf	0.02	0.00	7.6	lb/MMscf	0.07	0.00	0.37	lb/MMBtu	3.7	0.00	5.0E-04	lb/MMscf	4.9E-06	2.44E-09	1.84E-04	lb/MMscf	1.8E-06	8.94E-10	1.20E-05	lb/MMscf	1.2E-07	5.84E-11
T-530	0.00638	MMscfh	9,880	7,000	1.0	0.33					0.068	lb/MMBtu	1.4	0.00	see below[2]		2.5	0.00	1.9	lb/MMscf	0.04	0.00	7.6	lb/MMscf	0.16	0.00	0.37	lb/MMBtu	7.8	0.00	5.0E-04	lb/MMscf	1.0E-05	5.15E-09	1.84E-04	lb/MMscf	3.8E-06	1.89E-09	1.20E-05	lb/MMscf	2.5E-07	1.24E-10

	VOC[3]		NO_X		SO_2		PM		$PM_{10}/PM_{2.5}$		CO		Pb		Hg		Be	
Total Projected Actual Emissions				4.4E-03		0.01		1.2E-04		4.8E-04		0.02		3.1E-08		1.2E-08		7.6E-10
Major New Source Review Thresholds		40		40		40		25		15		100		0.6		0.1		0.1
Major New Source Review Triggered?		No		No		No		No		No		No		No		No		No

[1] Event emission rate represents one worst case emergency/malfunction scenario event. Annual emission rate represents the estimated annual average total duration of worst case emergency/malfunction events.

[2] SO_2 Emissions Calculation:

SO2 MW (lb/lb-mole)=		64

SO2 emissions are calculated based on the concentration of sulfur in the gas stream, the ideal gas law, and the molecular weight of SO2.

General Assumptions Used in Calculations

Variable	Value	Units
V	1,000,000	ft^3
P	14.7	psia
R	10.73	psia-ft^3/lbmol-R
T	527.7	R
md	2596.15	lbmols/MMscf
	385.1851	scf/lbmol

Ideal Gas Law used to determine the moles of gas per MSCF (P*V=n*R*T)

[3] Note that VOC emissions will actually decrease with respect to the current scenario where releases are not vented to the Flare since they will be controlled by the Flare; therefore, the potential VOC emissions associated with emergencies and malfunctions will decrease. Refer to the application text for more information.

Other Notes:
- Natural gas Higher Heating Value (Btu/scf) = 1020
- The VRU WARP project ties existing blowdown RVs to the VRU Flare header system from VRU 100 and VRU 200 and consists of emergency RVs only. Nitrogen will be used as the purge gas for the new header tie-ins.
- No modifications to the flare, flare knockout drum, or piping from the knockout drum to the flare required modifications to accommodate the worst case emergency relief scenarios when considering the worst case relief scenarios for the current operations
- Regulatory applicability for 40 CFR 63, Subpart CC will not change as a result of the project. Emergency RVs are not miscellaneous process vents per 40 CFR 63, Subpart CC since they are exempted from the definition in 40 CFR 63.641
- RV release gas combustion emission factors for PM/PM10/PM2.5, Lead, Beryllium and Mercury are from AP-42 Section 1.4 (July 1998). Emission factors for VOC, NOx, and CO are from AP-42 Section 13.5 (September 1991). The emissions for SO2 are calculated
- It was also conservatively assumed that each RV would lift one time per year, although this is an unlikely scenario.

Fugitive Emission Calculations for TK-3637

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	0	0.5789	0.0013	2.0%	0.0000	95%	100%	0.00
Light Liquid	10	0.1878	0.0037	2.0%	0.0738	95%	100%	0.02
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Light Liquid	22	0.0827	0.00013	0.3%	0.0083	30%	100%	0.03
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.04**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Reference Data

3SPS potential emissions are presented below only for reference for determining the particulate emissions from the SCR. The 3SPS boilers will not be modified for this project since the SCR will be an add-on control.

Process Unit	Maximum Heat Capacity		VOC				NOx				SO2				PM				PM10/PM2.5				CO				Pb			
			EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy
3SPS	2,774	MMBtu/hour									24.45	lb/MMscf	56.4	246.9																
Fired Heater	198	MMBtu/hour	5.5	lb/MMscf	1.1	4.7	0.05	lb/MMBtu	9.89	43.3	26.44	lb/MMscf	4.3	19.0	1.9	lb/MMscf	0.4	1.6	7.6	lb/MMscf	1.5	6.5	0.02	lb/MMBtu	4.0	17.3	5.0E-04	lb/MMscf	9.7E-05	4.2E-04

NOx emissions calculated above are pre-SCR, uncontrolled emissions.

Conversion Rate	3.0%
NOX Reduction (from inlet to SCR)	95%
NSPS J Limit (ppm)	159
TRS Reported in 2005 (ppm)	147
Calculated SO2 Emission Factor at NSPS J Limit (lb/MMscf)	26.44
Calculated SO2 Emission Factor at Current Maximum Average TRS (lb/MMscf)	24.45
Duct Burner ppm sulfur	159.00
Duct Burner SO2 Emission Factor (lb/MMscf)	26.44
Refinery Fuel Gas HHV (BTU/scf)	1203.33
3 SPS Boiler Utilization Factor	0.965

Project Potential to Emit Increase - for permitting level applicability

Conversion to Ammonium Sulfate

Control Device	SO_2 to SO_3 Conversion Rate		VOC				NOx				SO2				PM				PM10/PM2.5				CO				Pb				Sulfuric Acid Mist				Mercury				Beryllium			
			EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy
SCR Impact on Boilers	3.0%	% Conversion Rate	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a					n/a	n/a	3.5	15.3	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Duct Burners	198	MMBtu/hour			1.1	4.7			9.9	43.3			4.3	19.0	1.9	lb/MMscf	0.4	1.6			1.7	7.6			4.0	17.3			0.0	0.0				0.9	1.8E-07	lb/MMBtu	3.6E-05	1.6E-04	1.2E-08	lb/MMBtu	2.3E-06	1.0E-05
Project PTE						4.7				43.3				19.0								22.9				17.3								0.9				1.6E-04				1.0E-05
Project PTE (with NOx controls included)						4.7				2.2				19.0								22.9				17.3																
Part 70 Minor						**2.7**				**4.6**				**10**								**5**				**25**																
Part 70 Significant						**25**				**25**				**25**								**25**				**100**																
Part 70 Permit Required?						**Yes**				**Yes**				**Yes**								**Yes**				**No**																

Project Emissions Increase - for major NSR applicability

Potential 3SPS Gas Usage Rate (based on maximum heat input capacity and utilization factor)	Potential SO2			
MMscf/year	EF	Unit	lb/hr	tpy
20,196.89	24.45	lb/MMscf	n/a	246.9
Potential Duct Burner SO2 Emissions	26.44	lb/MMscf	4.3	19.0
Total Potential SO2 Emissions				265.9

Conversion to Ammonium Sulfate

Control Device	SO_2 to SO_3 Conversion Rate		VOC				NOx				SO2				PM				PM10/PM2.5				CO				Pb				Sulfuric Acid Mist				Mercury				Beryllium			
			EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy	EF	Unit	lb/hr	tpy
SCR Impact on Boilers	3.0%	% Conversion Rate	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a					n/a	n/a	n/a	15.3	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Duct Burners	198	MMBtu/hour				4.7				2.2				19.0	1.9	lb/MMscf	0.4	1.6				7.6				17.3				0.0	n/a	n/a	n/a	0.87	1.8E-07	lb/MMBtu	3.6E-05	1.6E-04	1.2E-08	lb/MMBtu	2.3E-06	1.0E-05
Project Emissions Increase						4.7				2.2				19.0				1.6				22.9				17.3				4.2E-04				0.9				1.6E-04				1.0E-05
Duct Burner and SCR Baseline Emissions						-				-				-				-				-				-				-				-				-				-
Project Emission Increase (Potential - Baseline)						4.7				2.2				19.0				1.6				22.9				17.3				4.25E-04				0.9				1.6E-04				1.0E-05

Assumptions:

- Maximum Heat Input Capacity = 575 MMBtu/hr *5 Boilers *96.5% availability at 3SPS
- Projected actual gas usage rates are based on assuming 8,760 hours of operation at the maximum permitted capacity.
- No credit is currently taken for NOx reductions from the boilers.
- Post -SCR NOx emissions are based on vendor guarantee emission rates using SCR technology.
- Since the duct burners are new units, PTE is used for the projected actual emissions.
- SO2 emissions are calculated using Refinery fuel gas HHV before the CXHD project and the Ideal Gas Law
- Fuel Gas Heating Value = 1203.3 BTU/scf
- Natural Gas Heating Value = 1020 BTU/scf

-Ammonium Sulfate Molecular Weight = 132.14
-Sulfur Trioxide Molecular Weight = 80.06
- Sulfur Dioxide Molecular Weight = 64.06
- Sulfuric Acid Mist Molecular Weight = 98.07
- BP is conservatively considering that all of the SO_3 emitted can form both condensable particulate matter and sulfuric acid mist.
- Fraction of SO_3 converted to Sulfuric Acid Mist = 1
- Moles in 1 MMscf (n from Ideal Gas Law) (lbmol/MMscf) 2596.15 *Derived from the Ideal Gas Law, assuming V = 1MMscf, P = 14.7 psia, T = 527.7 R, R = 10.73 psia-ft^3/lbmol-R*

Fugitive Emission Calculations for New Boilers

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	126	0.5789	0.0013	2.0%	1.6194	95%	100%	0.35
Light Liquid	0	0.1878	0.0037	2.0%	0.0000	95%	100%	0.00
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	76	0.0827	0.00013	0.3%	0.0287	30%	100%	0.09
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	3	3.728	0.0985	2.0%	0.5133	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	1	0.0827	0.00013	2.0%	0.0018	0%	100%	0.01
							Total VOC Emissions (tons/yr):	**0.45**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Fugitive Emission Calculations for Fuel Gas Lines for 3 SPS SCR Duct Burners

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	150	0.5789	0.0013	2.0%	1.9278	95%	100%	0.42
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	255	0.0827	0.00013	0.3%	0.0963	30%	100%	0.30
Light Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Heavy Liquid	0	0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	0	3.728	0.0985	2.0%	0.0000	100%	100%	0.00
Open-ended Lines	10	0.02635	0.0033	2.0%	0.0376	0%	100%	0.16
Sampling Connections	0	0.0827	0.00013	2.0%	0.0000	0%	100%	0.00
							Total VOC Emissions (tons/yr):	**0.88**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500//10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

1131	Required Boiler Heat Input (MMBTU/hr)* (2 boilers at 580 MMBtu/hr each at 97.5% total annual utilization)

8760	Hours of Operation

Conservative Emissions Case

Pollutant	Emission Factor** (lb/MMBtu)	Emissions (lb/hr)	Emissions (tpy)
NOx	0.065	73.5	322.0
SO2	***	20.0	49.8
PM	0.002	2.1	9.2
PM10/PM 2.5	0.007	9.7	40.0
CO	0.024	27.1	118.9
VOC	0.005	6.1	26.7
Sulfuric Acid Mist	5.E-04	0.5	2.3
Lead	4.9.E-07	6.E-04	2.E-03
Mercury	1.8E-07	2.E-04	9.E-04
Berylllium	1.18E-08	1.E-05	6.E-05

0.065	NOx (lb/MMBtu)
0.007	PM10/PM2.5 (lb/MMBtu)
0.024	CO (lb/MMBtu)
0.005	VOC (lb/MMBtu)
3%	% Conversion of SO2 to SO3
64.06	Molecular Weight of SO2
98.07	Molecular Weight of H2SO4

** EF Notes:

1) NOx factor based on manufacturer's guarantee (control technology/technique to be determined)

2) SO2 emissions will be limited to 24.9 tpy per boiler and emissions will be calculated based on total sulfur in refinery fuel gas. Natural gas blending will be used, if necessary.

3) PM based on AP-42 Table 1.4-2.

4) PM10/PM2.5 emission factor based on AP-42 Table 1.4-2 total particulate (condensible and filterable); Note that additional PM10/PM2.5 emissions were added, assuming that an SCR may be added to the boilers and 3% conversion of SO2 emissions to SO3 and ammonium sulfate.

5) CO based on manufacturer's guarantee.

6) Refinery fuel gas heating value assumed to be 1200 BTU/scf

7) VOC based on AP-42 Section 1.4 for natural gas

8) Lead, beryllium, and mercury emissions based on AP-42 Section 1.4 for natural gas.

9) Sulfuric Acid Mist emissions based on assumed conversion percentage of SO2 to SO3 and the assumption that all SO3 converts to sulfuric acid mist.

Refinery Fuel Gas HHV (BTU/scf)	1200
Natural Gas HHV (BTU/scf)	1020
Natural Gas SO2 Emission Factor (lb/MMscf)	0.6
Refinery Fuel Gas SO2 Emission Factor (at S ppm listed above) (lb/MMscf)	0.0

3 SPS Baseline for CO Reduction

F-factor	
8710	scf/mmbtu
7.27E-08	K-factor for CO
28	CO MW

CO and O2 Analyzer Data:

	%O2		CO (ppm)		MMSCF/yr		BTU/scf		MMBTU/yr		lb/MMBTU		CO (tpy)	
	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005	**2004**	**2005**
Boiler 31	9.36	8.45	27.24	90.9	2690.84	2749.28	1150.09	1279.182	3,094,708	3,516,834	0.031248	0.096657	48.3512	169.9629
Boiler 32	6.21	9.59	24.85	20.3	3213.87	2408.26	1150.09	1279.182	3,696,238	3,080,596	0.022404	0.023803	41.40467	36.66309
Boiler 33	5.88	7.46	39.91	30.4	3173.27	2616.82	1150.09	1279.182	3,649,546	3,347,394	0.035174	0.02995	64.18397	50.12744
Boiler 34	8.96	8.17	15.77	53.5	2748.05	2703.50	1150.09	1279.182	3,160,510	3,458,261	0.017484	0.055669	27.62978	96.25842
Boiler 36	6.79	7.71	57.16	60.5	3045.04	2718.25	1150.09	1279.182	3,502,070	3,477,131	0.053638	0.060762	93.92229	105.6381
TOTAL												**TOTAL**	**275.4919**	**458.6499**

boiler	31	32	33	34	36	Total
Averages 2004-2005	**109.16**	**39.03388**	**57.15571**	**61.94410002**	**99.78019**	367.07

Notes:
- %O2, ppm CO and MMSCF/yr are annual average values obtained from averaging monthly CEMS and analyzer data
- Note that this conservatively uses CO analyzer data instead of the data reported in the TRI/I-Steps based on the emission factor.

Potential to Emit for 3 SPS Boilers Based on Vendor Guaranteed Emission Factor and Limited Utilization Factor of 96.5%

Process Unit	Maximum Heat Capacity		CO				
			EF	Unit	lb/hr	tpy	
3SPS 1	555	MMBtu/hour	0.02	lb/MMBtu	11.1	48.6	per boiler
3SPS 2	555	MMBtu/hour	0.02	lb/MMBtu	11.1	48.6	
3SPS 3	555	MMBtu/hour	0.02	lb/MMBtu	11.1	48.6	
3SPS 4	555	MMBtu/hour	0.02	lb/MMBtu	11.1	48.6	
3SPS 6	555	MMBtu/hour	0.02	lb/MMBtu	11.1	48.6	

CO Emission Factor is based on vendor guarantee.

CO Emissions Reductions from 3 SPS Boilers

Boiler	CO	
	tpy	
1	(60.5)	*Future Potential CO Emissions - Past Actual CO Emissions*
2	9.6	
3	(8.5)	
4	(13.3)	
6	(51.2)	
Total	**(124.0)**	*Total CO Reduction*

Tank 8

Tank 8 is an oil/water separator that currently handles the wastewater associated with the 11 Pipe Stills. This is a new oil/water separator system that may eventually replace Tank 8; however, both may operate for a period of time.

Estimated New Fugitive Components Associated with the Tank 8 Oil/Water Separator System

Component Type	# of components
Valves	
Gas/Vapor	15
Light Liquid	15
Heavy Liquid	50
Pumps	
Light Liquid	
Heavy Liquid	15
Flanges	
Gas/Vapor	20
Light Liquid	20
Heavy Liquid	40
Compressors	0
Relief Valves	5
Open-ended Lines	0
Sampling Connections	8

New Tank 8 Oil/Water Separator System

Maximum average daily estimated flow rate of material through the new Tank 8 oil/water separator (gal/day)	100,000	*Based on design estimates*
VOC Emission Factor (lb/kgal)	0.2	*Covered Oil/Water Separator from AP-42 Table 5.1-2 (1/95)*
VOC Emissions (lbs/day)	20	*Maximum average daily flow rate * VOC Emission Factor*
VOC Emissions (tpy)	3.7	*VOC Emissions lbs/day * 365 days /yr * 1 ton/2,000 lbs*

Note that the oil/water separator will be subject to the requirements of 40 CFR 61, Subpart FF and will be equipped with carbor canisters to control emissions.
Note that a new junction box and new manhole and sewer drain may be installed, depending on the final location chosen within the refinery.

Fugitive Emission Calculations for Tank 8 OWS Replacement

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	15	0.5789	0.0013	2.0%	0.1928	95%	100%	0.04
Light Liquid	15	0.1878	0.0037	2.0%	0.1107	95%	100%	0.02
Heavy Liquid	50	0.00051	0.00051	2.0%	0.0255	30%	100%	0.08
Pumps								
Light Liquid	0	0.9630	0.0265	2.0%	0.0000	80%	100%	0.00
Heavy Liquid	15	0.8565	0.02976	2.0%	0.6944	30%	100%	2.13
Flanges								
Gas/Vapor	20	0.0827	0.00013	0.3%	0.0076	30%	100%	0.02
Light Liquid	20	0.0827	0.00013	0.3%	0.0076	30%	100%	0.02
Heavy Liquid	40	0.0827	0.00013	0.3%	0.0151	30%	100%	0.05
Compressors	0	3.545	0.1971	2.0%	0.0000	0%	100%	0.00
Relief Valves	5	3.728	0.0985	2.0%	0.8555	100%	100%	0.00
Open-ended Lines	0	0.02635	0.0033	2.0%	0.0000	0%	100%	0.00
Sampling Connections	8	0.0827	0.00013	2.0%	0.0143	0%	100%	0.06
							Total VOC Emissions (tons/yr):	**2.43**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500/10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Relief Valves are controlled

Diesel Fire Pump Engines Emissions

There are three identical diesel fire pump engines

Hours of Operation	500	*Emergency fire pump engines used for the fire water system*
Number of Engines	3	
Engine HP	390	*Actual mechanical HP estimated based on the mechanical effciency, assumed 0.9*
Load Factor	100%	*Conservatively assumes that pump engine is operated at 100% load, actual load depends on operating point of engine/pump combination*

		NO_x		CO		$PM/PM_{10}/PM_{2.5}$		SO_x		VOC
		AP-42	NSPS IIII	AP-42	NSPS IIII	AP-42	NSPS IIII	AP-42	Low Sulfur Diesel	AP-42
Emission Factor (lb/hp*hr)		0.031		0.00668		0.0022		0.00205		0.00251
Emission Factor (g/hp*hr)		14.0616	**7.8**	3.030048	**2.6**	0.99792	**0.4**	0.92988	**0.161**	1.138536
Emission Factor (g/kw*hr)		18.848	**10.5**	4.06144	**3.5**	1.3376	**0.54**	1.2464		1.52608
Emissions (lb/hr)	each engine	6.71		2.24		0.34		0.14		0.98
Emissions (tpy)	each engine	1.68		0.56		0.09		0.03		0.24
Total Emissions (lb/hr)		20.12		6.71		1.03		0.42		2.94
Total Emissions (tpy)		5.03		1.68		0.26		0.10		0.73

Notes

Emission factors are from AP-42 Section 3.3, Table 3.3-1 (10/96) and NSPS Subpart IIII.
VOC emission factor is the sum of the TOC emission factors for exhaust and crankcase.
PM is assumed to be equal to PM_{10} for the purposes of these calculations. It should be noted that AP-42 Section 3.3 does not include a PM emission factor, and footnote b of Table 3.3-1 indicates that all particulate is assumed to be less than 1 micrometer.
Emission factors noted in red are emission standards for engine 300~600 HP, per 40 CFR 60, Subpart IIII
Emission estimates are based on the lower of AP-42 emission factors and Subpart IIII emission limits
40 CFR Subpart IIII limits NOx + NMHC. NOx assumed emitted at Subpart IIII limit and VOC emitted at AP-42 factor levels.
SO2 emission factor based on NSPS limit of 500 ppm fuel sulfur content and calculations below.

Sample Calculation

NOx emissions from compressor (lb/hr) = $\frac{390\text{ hp}}{} \cdot \frac{7.8\text{ g NOx}}{\text{hp-hr}} \cdot \frac{\text{lb}}{453.6\text{ g}} \cdot 100\% \cdot 3\text{ engines}$ = 20.12 lb NOx/hr

SO2 emission factor calculation: $\frac{0.0005\text{ lb S}}{\text{lb diesel}} \cdot \frac{7.1\text{ lb diesel}}{\text{gal diesel}} \cdot \frac{\text{gal diesel}}{.140\text{ MMBtu}} \cdot \frac{2\text{ lb SO2}}{\text{lb S}} \cdot \frac{7000\text{ MMBtu}}{10^6\text{ hp-hr}} \cdot \frac{453.6\text{ g}}{\text{lb}}$ 0.161g SO2/hp-hr

Conversion factors found in AP-42 Table 3.3-1 were used above to calculate engine fuel efficiency in MMBtu/hp-hr

Summary of Dewatering and Thermal Desorption System Project
Emission Calculations

	VOC (tons/yr)	NOx (tons/yr)	PM (tons/yr)	PM10/PM2.5 (tons/yr)	CO (tons/yr)	SO2 (tons/yr)
Dewatering Emissions	0.9	n/a	n/a	n/a	n/a	n/a
Thermal Desorption Emissions (Burners and VOC)	1.0	5.2	0.5	0.8	1.3	1.8
Fugitive Equipment Components	0.6	n/a	n/a	n/a	n/a	n/a
TOTAL	2.4	5.2	0.5	0.8	1.3	1.8
PERMITTING STATUS	**EXEMPT**	**PERMIT REQUIRED**	**EXEMPT**	**EXEMPT**	**EXEMPT**	**EXEMPT**
Permitting Thresholds:						
Part 70 Minor Source Mod	2.7	4.6	5	5	25	10
Part 70 Significant Source Mod	25	25	25	25	100	25

Potential Emissions Calculations for Dewatering System

Refer to the application text for a description of the dewatering system.

Mass Balance Emissions Calculation

Maximum values from sludge analytical data from 2000 to 2002 documented in Hazardous Waste Combustor MACT Performance Test Plans

		DAF Float/Biosolids	API Sludge
Method 8270 (SVOCs)		mg/kg	mg/kg
Anthracene		9.9	ND
Chyrsene		16.5	ND
Naphthalene		149	47
Phenanthrene		97.7	33
Pyrene		30.95	33
	Total SVOCs	**304.05**	**113**
Method 8260 (VOC)			
Benzene		110	20
Ethylbenzene		245	48
Toluene		530	66.5
Xylenes		700	180
	Total VOC	**1585**	**314.5**

Dewatering System Capacity

Density of Water (lb/gal)		8.34
Conversion Factor (lb/g)	0.0022	
Conversion Factor (mg/g)	1000	
Conversion Factor (g/kg)	1000	
Total SVOCs (lb/lb)	0.00030405	
Total VOCs in Feed (lb/lb)	0.001585	
Potential SVOC and VOC throughput (lb/lb)	0.00188905	*Sum of SVOCs and VOCs in feed*
VOC Control Efficiency (%)	95%	*Based on 40 CFR 61, Subpart FF requirements; Note that carbon actually provides a 99.9% control efficiency if monitored for breakthrough and changed after breakthrough is detected (per carbon system vendors); however, 95% used as a conservative measure in accordance with regulatory requirements.*
Thermal Desorption System Feed Rate Capacity (tons feed/year)	22500	*Based on system design (range of 18,000 to 20,000, depending on solids percentage of feed)*
Concentration Ratio of Dewatering system	4	*Typical design solids concentration ratio of sludge processed in dewatering system (pre to post dewatering system)*
Dewatering System Feed Rate Capacity (tons feed/year)	90000	*Based on system design of thermal desorption system * concentration ratio of dewatering system (range of 18,000 to 20,000, depending on solids percentage of feed)*
Percentage of Volatile Material Processed Emitted at Dewatering (%)	10%	*Engineering estimate based on relative non-volatility of material remaining in sludges after processing steps prior to dewatering system. Note that most of the oil will be recovered in the dewatering and thermal desorption system.*
Potential Uncontrolled SVOC and VOC emissions (tpy)	17.00	
Potential Controlled SVOC and VOC emissions (tpy)	**0.85**	

Thermal Desorption System

The thermal desorption system is a closed system with the exception of vents for the processed solids system, the noncondensible stream that is vented to the system burners, and the burner emissions. Refer to the application for a detailed description.

Waste Stream Composition Estimates

Solids (% by weight from the dewatering system)	40%	*Based on conservative typical design estimates*
Water (% by weight from dewatering system)	40%	*Based on conservative typical design estimates*
Oil (% by weight from dewatering system)	20%	*Based on conservative typical design estimates*

System Capacity Information

System Oil Recovery Estimate (% by weight)	80%	*Based on conservative design estimates - 90% recovery is typically expected*
Noncondensible Portion Estimate (% by weight)	20%	*Based on conservative design estimates - 10% noncondensibles are typically expected*
System Production Capacity (dry tons solids produced/year)	9000	*Based on system design*
System Feed Rate Capacity (tons feed/year)	22500	*Based on system design (range of 18,000 to 22,500, depending on solids percentage of feed)*

Noncondensible Hydrocarbons Routed to Burner

Assumes that negligible amounts of organic material will be left in recovered solids after thermal desorption and that all the material that is not recovered is included in the noncondensibles portion. Note that the noncondensible portion will consist of hydrocarbons that do not condense at above 150 to 160 degrees F such as methanes and propanes.

Oil in Feed (tpy)	4500	*Percent by weight oil in feed * System Feed Rate Capacity*
Noncondensible Portion of Oil in Feed (tpy)	900	*Percent by weight noncondensible portion * Oil in Feed*
VOC Control Efficiency (%)	99.9%	*Based on vendor tests for other applications of the thermal desorption system*
Potential VOC Emissions (tpy)	0.9	*Noncondensible Portion of Oil in Feed * (1-VOC Control Efficiency)*

Based on the previous experience of the vendor with other waste streams that contain sulfur compounds, hydrogen sulfide in the stream from the thermal desorption unit is typically absorbed in the condensed oil and elemental sulfur typically remains in the solids. The sulfur emissions from the fuel burned in the burner typically are greater than those from the supplemental noncondensible stream.

Processed Solids System

It is presumed that negligible amounts of VOC will be emitted from the recovered solids since they have been processed through the thermal desorption system. In addition, the recovered solids system will be enclosed for the rehydration process and routed to a wet scrubber. Therefore, the controlled emissions are presumed to be neglible.

Diesel Fired Burner Emissions

The thermal desorption system is equipped with two burners that burn distillate fuel. In addition, the noncondensible vapor stream is routed through the burners for destruction of the lighter hydrocarbons that are not recovered in the oil. Note that the noncondensible portion will consist of hydrocarbons that do not condense at above 150 to 160 degrees F such as methanes and propanes.

Distillate Firing Emissions:

Hours of Operation	8760	
Burner Rating (MMBtu/hr)	8	*Total maximum rating of two burners*
Density of Diesel Fuel (lb/gal)	7.05	
Heating Value of Fuel (Btu/lb)	19,300	*From note in AP-42 section 3.3 below table 3.3-1*
Heating Value of Fuel (Btu/gal)	137,000	*From AP-42 Appendix A, Typical parameters of various fuels*
Fuel Consumed (lb/hr)	414.51	
Fuel Consumed (gal/hr)	59	
Fuel Consumed (gal/day)	1411	*Based on maximum burner capacity; Note that 750 to 1000 gallons per day is the expected usage rate*
Fuel Sulfur %	0.05	*As required by 40 CFR 80.29(a)(1) - distillate produced by BP Whiting*

Criteria Pollutants

	NO_x	**CO**	**SO_2**	**PM_{10} (Filterable)**	**$PM_{10}/PM_{2.5}$ (Filterable + Condensable)**	**VOC**
AP-42 Emission Factor (lb/kgal)	20	5	7.1	2	3.3	0.2
Emissions (lb/hr)	1.18	0.29	0.42	0.12	0.19	0.01
Emissions (tpy)	5.15	1.29	1.83	0.52	0.85	0.05

Other Pollutants

	Lead	**Mercury**	**Beryllium**	**Benzene***
AP-42 Emission Factor (lb/10^12 Btu)	9	3	3	2.14E-04
Emissions (lb/hr)	0.00	0.00	0.00	<0.01
Emissions (tpy)	0.00	0.00	0.00	<0.01

Notes

Emission Factors taken from AP-42 Section 1.3 tables 1.3-1, 1.3-2, 1.3-3 assuming boiler fired by No. 2 oil (9/98).
VOC emission factor is NMTOC factor from AP-42 Section 1.3-3 (9/98).
SO2 emission factor = 142 * Fuel Sulfur % (AP-42, Section 1.3, Table 1.3-1, 9/98).
PM_{10} emission factor is sum of filterable and condensable factors from Tables 1.3-1 and 1.3-2.
PM is assumed to be equal to filterable factor only for purposes of these calculations.
*Other pollutant emission factors are from Tables 1.3-9 and 1.3-10. The benzene emission factor is in lb/kgal.

The thermal desorption system will use the existing diesel tank associated with the FBI system. In addition, the thermal desorption system will use less fuel than the existing FBI system has used in the past; therefore, no increases associated with the tank are included.

Sample Calculation

NOx Emissions (lb/hr) = $\frac{8\text{ MMBtu}}{\text{hr}} \times \frac{1000000\text{ Btu}}{\text{MMBtu}} \times \frac{\text{lb}}{19300\text{ Btu}} \times \frac{\text{gal}}{7.05\text{ lb}} \times \frac{\text{kgal}}{1000\text{ gal}} \times \frac{20\text{ lb}}{\text{kgal}}$ = 1.18 lb/hr

Process Gas Stream Combustion Emissions:

Note that the distillate fuel use will be adjusted as the noncondensible portion provides heat input capacity such that the maximum rating of the burners will remain at 4 MMBtu/hr each. Therefore, the emissions calculated for the burners should account for all combustion emissions; however the emissions from the combustion of the vapors are calculated below for reference in determining if the emissions are higher when firing process gas in lieu of some of the diesel.

Potential VOC in Noncondensible Stream (tpy)	900	
Molar Volume (L/mol)	22.41	*Volume of 1 mole of gas, based on the ideal gas law equation at standard conditions*
SO2 Molar Weight	64.06	*lb/lb-mol or g/mol*
VOC Vapor Molar Weight (lb/lb-mole)	130	*Vapor molecular weight of distillate number 2 from TANKS 4.09d*
Conversion Factor (L/cf)	28.32	
Conversion Factor (lb/g)	0.0022	
Total VOC Routed to Burners (lb-mole/hr)	1.58	
Converted Molar Volume of gas (scf/lb-mol)	359.80	
Total Volume of Organic Vapors Combusted (MMscf/hr)	5.69E-04	*Based on the total VOC combusted per hour multiplied by the molar volume of the gas*
Total Volume of Vapors Combusted (MMscf/yr)	4.98E+00	*Based on the total VOC combusted per year multiplied by the molar volume of the gas*
Higher Heating Value of Refinery Fuel Gas (MMBtu/MMscf)	1200	*Conservatively assumes that the gas has a similar heating value to refinery fuel gas, although the heating value will vary.*
Higher Heating Value of Natural Gas (MMBtu/MMscf)	1020	*This is used to convert the natural gas emission factors per footnote a in Table 1.4-1 of AP-42 Section 1.4.*
Sulfur Concentration (ppm)	46.03	*Based on the average hydrogen sulfide content of the refinery fuel gas from 2003-2004. This conservatively assumes the same H2S concentration as refinery fuel gas; however, the H2S is not expected to be present in significant quantities in the noncondensible stream since it should be absorbed in the oil condensing phase.*

	NO_x	CO	SO_2	$PM/PM_{10}/PM_{2.5}$
Emission Factor based on Natural Gas (lb/MMscf)	100	84	see below	7.6
Burner Exhaust Emissions (lb/hr)	0.07	0.06	0.06	<0.01
Burner Exhaust Emissions (tpy)	0.29	0.25	0.28	0.02

Converted Flow Rate to Burners (MMscf/hr)	0.008	*Conservatively based on natural gas heat input and the maximum capacity of the burner*
SO2 Emission Rate (lb/hr)	0.06	
SO2 Emission Rate (tpy)	0.28	

The emissions associated with the diesel burners are higher than emissions when burning process gas; therefore, the diesel burner emissions will be used for potential emissions estimates.

Notes

Emissions factors for NO_X, CO, PM_{10} are from AP-42 Section 1.4 tables 1.4-1 and 1.4-2 (7/98) assuming combustion similar to natural gas.
PM is assumed to be equal to PM_{10} and $PM_{2.5}$ or the purposes of these calculations.
Molar volume for VOC and SO2 calculated using ideal gas law at standard temperature and pressure.
These calculations are conservative as the noncondensible stream is not likely to contain as much hydrogen sulfide as the refinery fuel gas.
Note that it is presumed that the sulfur compounds in the noncondensible stream will mostly be H2S. Other reduced sulfur compounds that could be formed in the thermal desorption unit have similar boiling points to the hydrocarbons that are condensed and recovered, and these other sulfur compounds are expected to condense in the oil phase with the hydrocarbons.

Fugitive Emission Factors

Equipment/Service	EPA Refinery Average Emission Factors Kg/hr/source	EPA Refinery Average Emission Factors lbs/hr/source	EPA Refinery SCREENING Emission Factors - LEAK Kg/hr/source	EPA Refinery SCREENING Emission Factors - LEAK lbs/hr/source	EPA Refinery SCREENING Emission Factors - NO LEAK Kg/hr/source	EPA Refinery SCREENING Emission Factors - NO LEAK lbs/hr/source
Valves						
Gas/Vapor	0.0268	0.059083816	0.2626	0.5789	0.0006	0.0013
Light Liquid	0.0109	0.024030358	0.0852	0.1878	0.0017	0.0037
Heavy Liquid	0.00023	0.000507063	0.00023	0.00051	0.00023	0.00051
Pumps						
Light Liquid	0.114	0.25132668	0.437	0.963	0.012	0.0265
Heavy Liquid	0.021	0.04629702	0.3885	0.8565	0.0135	0.02976
Flanges						
Gas/Vapor	0.00025	0.00055	0.0375	0.0827	0.00006	0.00013
Light Liquid	0.00025	0.00055	0.0375	0.0827	0.00006	0.00013
Heavy Liquid	0.00025	0.00055	0.0375	0.0827	0.00006	0.00013
Compressors	0.636	1.40214	1.608	3.545	0.0894	0.1971
Relief Valves	0.16	0.35274	1.691	3.728	0.0447	0.0985
Open-ended Lines	0.0023	0.00507	0.01195	0.02635	0.0015	0.0033
Sampling Connections	0.015	0.03307	0.0375	0.0827	0.00006	0.00013

Reference:

A Factors are taken from EPA Document EPA-453/R-95-017, Nov. 1995, Table 2-2, Page 2-13.

B Factors are taken from EPA Document EPA-453/R-95-017, Nov. 1995, Table 2-6, Page 2-20.

Fugitive Emission Calculations for Dewatering and Thermal Desorption System

It is conservatively assumed that the components are in light liquid or vapor service, although the components may be in heavy liquid service. Only the new components associated with the new portions of the sludge handling system are included here.

LDAR Program: Monitoring per Consent Decree[1];

Factor Type: Refinery Screening (EPA Emission Factors EPA-453/R-95-017, Table 2-6)

Annual Hours of Service: 8760

Component Type	Estimated Component Count	EPA 'Refinery Screening' Factors LEAK (lb/hr/component)	EPA 'Refinery Screening' Factors NO LEAK (lb/hr/component)	Percent Leak	Maximum Uncontrolled Emission Rate (lbs/hr)	LD&R Control Efficiency[2]	Percent in VOC Service	Total VOC Emissions (Tons/yr)
Valves								
Gas/Vapor	22	0.5789	0.0013	2.0%	0.2827	95%	100%	0.06
Light Liquid	20	0.1878	0.0037	2.0%	0.1476	95%	100%	0.03
Heavy Liquid	0	0.00051	0.00051	2.0%	0.0000	30%	100%	0.00
Pumps								
Light Liquid	10	0.9630	0.0265	2.0%	0.4523	80%	100%	0.40
Heavy Liquid	0	0.8565	0.02976	2.0%	0.0000	30%	100%	0.00
Flanges								
Gas/Vapor	48	0.0827	0.00013	0.3%	0.0181	30%	100%	0.06
Light Liquid	60	0.0827	0.00013	0.3%	0.0227	30%	100%	0.07
Heavy Liquid		0.0827	0.00013	0.3%	0.0000	30%	100%	0.00
Compressors	0	3.545	0.197	2.0%	0.0000	0%	100%	0.00
Relief Valves	10	3.728	0.099	2.0%	1.7109	100%	100%	0.00
Open-ended Lines	0	0.026	0.003	2.0%	0.0000	0%	100%	0.00
Sampling Connections	2	0.083	0.00013	2.0%	0.0036	0%	100%	0.02
							Total VOC Emissions (lbs/day):	**3.46**
							Total VOC Emissions (tons/yr):	**0.63**

[1] United States, et.al v. BP Exploration & Oil, et.al., Northern District of Indiana, Hammond Division, Civil Action No. 2:96 CV 095 RL

[2] LD&R control efficiency for pumps and valves in gas and light liquid service are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv compared to the 10,000 leak definition basis for screening factors (i.e., (1-500//10,000 = 95%) and (1-2,000/10,000) = 80%)

AVO monitoring equivalent to 30% control is applied to all flanges and heavy liquid valves and pumps.

30% control estimate per TCEQ Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000).

Indiana Department of Environmental Management
Office of Air Quality

Appendix D to the
Technical Support Document (TSD) for a
Significant Source Modification (SSM) of a Part 70 Source and
Significant Permit Modification (SPM) of Part 70 Operating Permit

MODIFIED PERMIT SECTIONS

BP Products North America Inc., Whiting Business Unit
Significant Source Modification No.: 089-25484-00453
Significant Permit Modification No.: 089-25488-00453

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D.3	No. 12 pipe still	New heaters H-101A, H-101B, H-102
D.4	Sulfur Recovery Unit	New COT1 and COT2 tail gas units, tanks SH-1 and SH-2; Shutdown of B/S TGU, SBS TGU, SBS cooling tower and standby incinerator
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D.23	No. 1 Stanolind Power Station	shutdown of boilers 3, 4, 5, 6, 7
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D.26	Wastewater treatment plant	New storage tank 5052, brine treatment system with new tanks TK-101, TK-102, TK-103, TK-104B, TK-105A, and TK-105B

Section	Facility	Emissions Units/Description of Changes
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D.34	Marine dock facility	Installation of Vapor Recovery/Vapor Control Unit Modified Tank BT-002
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D.43 (new)	New Hydrogen Unit	New heaters HU-1 and HU-2, HU flare
D.44(new)	Additional units - non-CXHO contemporaneous projects	3 emergency firepump engines (390 HP), 2 boilers at 580 mmBTU/hr each
E.20	Boilers	Subpart DDDDD - vacated
E.21	Entire Source	NESHAP Subpart GGGGG
E.22	New Boilers	NSPS Subpart Db
E.23	Firepump engines	NSPS Subpart IIII
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List of Abbreviations

ARU	Aromatic Recovery Unit
BOU	Blending Oil Unit
COT	Claus Offgas Treater
CFHU	Cat Feed Hydrotreating Unit
CRU	Catalytic Refining Unit
CXHO	Canadian Extra Heavy Oil
DDU	Distillate Desulfurizer Unit
DHT	Distillate Hydrotreating Unit
FCU	Fluidized Catalytic Cracking Unit
GOHT	Gas Oil Hydrotreater
HU	Hydrogen Unit
ISOM	Isomerization Unit
PM	Particulate Matter (filterable only)
PM_{10}	Particulate Matter with diameter less than 10 microns (filterable + condensable)
PS	Pipestill
SPS	Stanolind Power Station
TAR	Turnaround Project
TGU	Tail Gas Unit
TRS	Total Reduced Sulfur
UF	Ultraformer
VRU	Vapor Recovery Unit

SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) and Hammond Department of Environmental Management. The information describing the source contained in conditions A.1 through A.3 and A.4 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)] [326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary refinery and marketing terminal.

Source Address:	2815 Indianapolis Blvd, Whiting, Indiana 46394-0170
Mailing Address:	P.O. Box 710, Whiting, Indiana 463940-170
General Source Phone Number:	219-473-3179
SIC Code:	2911
County Location:	Lake
Source Location Status:	Nonattainment for PM2.5 and 8-hour ozone standard Attainment for all other criteria pollutants
Source Status:	Part 70 Permit Program Major Source, under PSD and Emission Offset Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

A.2 Part 70 Source Definition [326 IAC 2-7-1(22)]

This stationary source consists of two (2) plants**, with a third plant located on an adjacent site:**

(a) The Whiting Refinery (previously designated 089-00003), located at 2815 Indianapolis Boulevard, Whiting, Indiana 46394; and

(b) The Marketing Terminal (previously designated 089-00004), located at 2530 Indianapolis Boulevard, Whiting, Indiana 46394.

(c) INEOS USA LLC (designated as 089-00076), 2357 Standard Avenue, Whiting, IN 46394.

Since the two (2) plants **(Whiting Refinery and the Marketing Terminal)** are located on contiguous or adjacent properties, the plants are under common control of the same entity, and the Whiting Refinery supports the Marketing Terminal, the two (2) plants are considered one (1) source.

In the case of the BP Whiting refinery and the INEOS USA LLC chemical plant, neither plant has a major role in the day-to-day operations of the other plant. There is no contract between the two companies concerning the acceptance or usage of raw materials. Each plant is free to obtain raw materials from other sources. The chemical plant has obtained raw materials from other sources in the past when the refinery has been unable to supply it. Neither plant provides a majority of its output to the other plant. Neither plant has the right to assume control of the other under any circumstance. The INEOS chemical plant purchases steam, water, wastewater service and a raw material stream from the BP refinery. If the refinery were to cease operations, the chemical plant could continue to operate.

The BP refinery purchases a hydrocarbon stream from the chemical plant. It also sends by-products to the INEOS chemical plant's flare. The flared by-products come from the venting of rail cars and the depressurizing of drums. The refinery does not rely on the hydrocarbon stream in order to produce its principal products. The refinery does not rely on the INEOS flare. If the INEOS chemical plant were to cease operations, the refinery could continue to operate. The refinery has a procedure in place on what steps its employees take when the INEOS flare is unavailable. Neither plant is dependent on the other to operate.

~~In regards to the refinery and the chemical plant, neither plant has a major role in the day-to-day operations of the other plant. There is no contract between the two companies concerning the acceptance or usage of raw materials. Each plant is free to obtain raw materials from other sources. The chemical plant has obtained raw materials from other sources in the past when the refinery has been unable to supply it. Neither plant provides a majority of its output to the other plant. Neither plant has the right to assume control of the other under any circumstance.~~

Since there is no common control, the refinery and the chemical plant are not part of the same major source. There is no need to examine the other two criteria under the definition of major source. Therefore, the chemical plant is not included in this Title V Operating Permit. The chemical plant will receive a separate operating permit.

A.3 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(15)]

This stationary source consists of the following emission units and pollution control devices:

(a) Nos. 11A and 11C Pipe Stills built in 1956, with a rated capacity of 220,800 barrels per day, and identified as Unit ID 120 process crude into various hydrocarbon fractions based on boiling points. This facility includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) The following process heaters, all of which are fired by natural gas, refinery gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-1X	250	120-01	None
H-2	45	120-02	None
H-3	55	120-03	None
H-200	249.5	120-05	**Current:** None **After CXHO: Low NOx Burners**
H-300	180	120-06	None

(2) Two (2) vacuum hot wells (D-21, constructed in 1990 and D-26, constructed in 21997) and one (1) sump (D-20, constructed in 1990), with D-20, D-21, and D-26 each venting to S/V 120-07, at No. 11 A Pipe Still.

(3) One (1) vacuum hot well (D-300), constructed in 1995 venting to S/V 120-08 at No. 11C Pipe Still.

The vacuum tower overhead system consists of a series of condensers, steam ejectors, and vacuum pumps. The majority of the overhead vapors are condensed and drained to the hotwell, which is pumped back to the front end of the unit for reprocessing. The gas compressors pull the remaining vapor that is not condensed in the overhead system into the wet gas system, where the hydrocarbon is reprocessed by down stream units. A thermocouple system (with temperature alarm) is used to monitor the vacuum on the system.

(4) Leaks from equipment in the process, including pumps; compressors (K4 and K4A at No. 11A Pipe Still and K300A and K300-B at the No. 11C Pipe Still); pressure relief devices; sampling connection systems; open-ended lines or valves; and instrumentation systems.

(5) One (1) storage tank (identified as Tank 3030) with a maximum storage capacity of 847,000 gallons. This tank was installed in 1957 and is equipped with an external floating roof.

(6) One (1) oil water separation system (identified as Tank 8) with a maximum storage capacity of 124,800 gallons.

(7) One (1) redundant oil water separation system (identified as Tank 8a), permitted in 2008, with a maximum storage capacity of 124,800 gallons, equipped with a carbon canister for VOC control.

(8) As part of the No. 11A PS and No. 11C PS WARP, permitted in 2008, the two existing blowdown stacks identified as stacks 11PS-A and 11PS-C will be shutdown, with the emergency pressure relief discharge that was previously routed to the blowdown stacks being re-routed to the DDU flare, except for T-300 vacuum tower relief discharge and the COV's.

(b) No. 11B Coker, which processes heavy crude fractions into coke, and Coke Pile. These facilities are identified as Unit 120 and are rated at 2,000 tons of coke per day. The facility includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Four (4) process heaters comprising:

Heater Identification	Maximum Heat Input Capacity	Stack Exhausted To	Emission Controls
H-101 H-102 H-103 H-104	200 (total)	120-04	None

(2) Storage and handling of the bulk material. Fugitive emissions are controlled by keeping the coke wetted and having a 15' sheet piling wall surrounding the coke pile. The coke pile height will not exceed 15'.

(3) The No. 11B Coker is connected to the DDU flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges and other connectors.

(Note: The No. 11B Coker and Coke Pile, heaters H-101, H-102, H-103, and H-104 will be replaced by the New Coker (#2 Coker) and Coke Handling System and heaters H-201, H-202, and H-203 as part of the CXHO project, identified later in this section).

New Coker (#2 Coker), constructed as part of CXHO project, which processes heavy crude fractions into coke, and new Coke Handling System. These facilities are identified as Unit 800 and are rated at 6,000 tons of coke per day. The New Coker (#2 Coker) heaters H-201, H-202, and H-203 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New Coker (#2 Coker) heater stacks have continuous emissions monitors (CEMS) for NOx and CO. The existing Coker and Coke Pile will be replaced as part of the CXHO Project. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) Process heaters comprising of:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted to	Emission Controls
H-201	208	800-01	Low-NO_X burners and selective catalytic reduction
H-202	208	800-02	Low-NO_X burners and selective catalytic reduction
H-203	208	800-03	Low-NO_X burners and selective catalytic reduction

(2) Storage and handling (including up to 10 transfer points) of the bulk material comprised of a partially enclosed crusher, enclosed conveyors, enclosed storage, day bins, and rail car load out under the main operating scenario. In order to minimize fugitive emissions from the coke handling process, transfer points 1 and 10 will include enclosed conveyors and transfer points 2 through 9 will use enclosed buildings, and water sprays. Coke handling operations will be expected to operate under this main operating scenario for at least 95% of operating hours annually.

There will also be an alternative operating scenario, which will consist of three enclosed conveyors with unenclosed transfer points. Coke handling operations are expected to operate under this alternate operating scenario for no more than 5% of operating hours annually.

(3) The Coker is connected to the South flare system (included in Section D.35). The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) One (1) storage tank, identified as TK-6255, with a maximum storage capacity of 14,028,000 gallons storing coker resid at a vapor pressure less than 0.5 psia. Tank TK-6255 is equipped with a fixed roof.

(5) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(c) No. 12 Pipe Still, constructed in 1959 **and to be modified as part of the CXHO Project**, which processes crude into various hydrocarbon fractions based on boiling points, identified as Unit ID 130, and is rated at 336,000 barrels per day. **Heaters identified as H-1AN, H-1AS, H-1B, H-2, H-1CN, H-1CS, and H-1CX will be shutdown and replaced by heaters H-101A, H-101B, and H-102 as part of the CXHO project.** The facility includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) The following process heaters, all of which are fired by natural gas, refinery gas, or liquified petroleum gas:

Heater Identification	Construction Date/Permitted Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-1AN	1959	121.5	130-01	None
H-1AS	1959	121.5	130-01	None
H-1B	1959	243	130-01	None
H-2	1959	174	130-01	Ultra low NO_x burners
H-1CN	1995	120	130-02	Low NO_x burners
H-1CS	1967	a	b	None
H-1CX	1977	410	130-04	Low NO_x burners
H-101A	**Permitted in 2008 (SPM 089-25488-00453)**	**355**	**130-05**	**Ultra low NOx Burners**
H-101B	**Permitted in 2008 (SPM 089-25488-00453)**	**355**	**130-07**	**Ultra low NOx Burners**
H-102	**Permitted in 2008 (SPM 089-25488-00453)**	**331**	**130-06**	**Ultra low NOx Burners**

[a] No longer in service -- was rated at 120 MMBtu/hour.
[b] No longer in service -- was exhausted to stack 130-03.

(2) One (1) vacuum hot well, identified as D-7, constructed in 1995, and venting to S/V 130-05. The vacuum tower overhead system consists of a series of condensers, steam ejectors, and vacuum pumps. The majority of the overhead vapors are condensed and drained to the hotwell, which is pumped back to the front end of the unit for reprocessing. The gas compressors pull the remaining vapor that is not condensed in the overhead system into the wet gas system, where the hydrocarbon is reprocessed by down stream units. A thermocouple system (with temperature alarm) is used to monitor the vacuum on the system.

(3) Leaks from process equipment.

(d) The Sulfur Recovery Unit (SRU) Facility, identified as Unit ID 162, originally constructed in 1971 and expanded in 1981 and 1995, and rated at 600 long tons per day, **to be modified as part of the CXHO Project, increasing the capacity to 1,300 long tons per day** of sulfur. The facility includes the following and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Three (3) three-stage Claus sulfur recovery trains, identified as A, B, and C**, and two (2) additional three-stage Claus sulfur recovery trains installed after modification, identified as D and E** trains.

(2) One (1) Beavon-Stretford tail gas unit (B/S TGU), a reduction system with a burner capacity of 24.3 MMBtu per hour, exhausting at stack S/V 162-02. **The B/S TGU will be decommissioned as part of the CXHO project.**

(3) One (1) tail gas unit (SBS TGU), an oxidation system with a burner capacity of 40 MMBtu per hour, exhausting at stack 162-04. The SBS TGU will be **decommissioned as part of the CXHO project.**

(4) One (1) caustic soda scrubbing tower to control sulfur dioxide emissions from the SBS TGU. **The caustic soda scrubbing tower will be decommissioned as part of the CXHO project.**

(5) One (1) cooling tower, identified as the SBS cooling tower, used to remove sodium bisulfite from the caustic scrubbing tower exhaust stream, equipped with a high-efficiency mist eliminator, and exhausting at stack 162-05. **The SBS cooling tower will be decommissioned as part of the CXHO project.**

(6) Gas quenching and cooling towers other than the SBS cooling tower**, to be decommissioned as part of the CXHO project.**

(7) One (1) quench separator with mist eliminators**, to be decommissioned as part of the CXHO project.**

(8) One (1) gas cooler and water condenser with sulfur dioxide stripper, **to be decommissioned as part of the CXHO project.**

(9) Caustic soda storage tanks and sodium bisulfite storage tanks, and handling equipment, **to be decommissioned as part of the CXHO project.**

(10) One (1) standby incinerator, used only in the event of an emergency, having stack ID S/V 162-01. **The standby incinerator will be decommissioned as part of the CXHO project.**

(11) One (1) flare, exhausting to stack S/V 162-03 which controls H_2S and VOC emissions during emergency situations, unit start-ups/shut-downs, and preparation of equipment for maintenance. Refinery or natural gas is used as a constant purge stream. Pilot gas is natural gas.

(12) One (1) modular degassing unit, which removes gases that are emitted during the cooling of molten sulfur. Removed gases are vented to the SBS TGU. **Removed gases will be vented to the front-end of Claus Trains D and/or E as part of the CXHO project.**

(13) Two (2) modular degassing units, to be installed as part of the CXHO project, which remove gases that are emitted during the cooling of molten sulfur. The gases will be vented to the front-end of Claus Trains D and/or E as part of the CXHO project.

(14) Three (3) sulfur pits, (Sulfur Pits A, B, and C) used to store molten sulfur with their vent stacks routed to the B/S TGU and/or the SBS. As part of the CXHO project, the vents from the sulfur pits A, B and C will be routed to either COT 1 and/or COT 2.

(15) Two (2) sulfur pits (Sulfur Pits D and E), to be installed as part of the CXHO project, used to store molten sulfur and the vents routed to either COT 1 and/or COT 2.

~~(13)~~ **(16)** One (1) sour water storage tank, identified as TK-431, having a maximum storage capacity of 845,600 gallons and equipped with an external floating roof. The maximum true vapor pressure of the material stored in this tank is less than 0.5 psia.

(17) One (1) sour water storage tank, identified as TK-410, permitted in 2008, having a maximum storage capacity of 4,351,200 gallons and equipped with an external floating roof. The maximum true vapor pressure of the material stored in this tank is less than 0.5 psia.

(18) Two (2) Claus Offgas Treaters (COT), identified as COT1 and COT2, to be installed as part of the CXHO project, thermal oxidation systems which combust natural gas, each rated at 72 mmBTU/hr, exhausting at stacks S/V 162-06 and 162-07.

(19) Two (2) sulfur storage tanks, identified as SH-1 and SH-2, each with a maximum storage capacity of 1,008,000 gallons and used to store molten sulfur exhausting to stacks S/V 163-09 and 162-10. These tanks will be constructed as part of the CXHO Project and are both fixed roof tanks controlled by a caustic scrubber.

Main Operating Scenario **Pre-CXHO**:
Approximately 80% of tail gases from the three trains are sent to the B/S TGU, with the remainder sent to the SBS TGU.

Alternate Operating Scenario #1 **Pre-CXHO**:
One train and the B/S TGU are not operated. Tail gases from the other two trains are sent to the SBS TGU.

Alternate Operating Scenario #2 **Pre-CXHO**:
The B/S TGU is not operated. Tail gases from the three trains are sent to the SBS TGU.

Alternate Operating Scenario #3 **Pre-CXHO**:
The SBS TGU is not operated. Tailgases from the three trains are sent to the B/S TGU.

Main Operating Scenario Post-CXHO:
The tail gases from the five trains are sent to both of the COTs.

Alternate Operating Scenario #1 Post-CXHO:
One of the COTs is not operated and the tail gases from the five trains are sent to the other COT.

(e) **(1)** Vapor Recovery Unit 100 (VRU-100) identified as Unit ID 241, and Vapor Recovery Unit 200 (VRU-200) identified as Unit ID 231**, permitted for turnaround (TAR) in 2008 to repair or replace tower trays and increase existing pumping and cooling capacities.** Gasoline and lighter products from the FCUs are separated in the VRUs using a series of distillation towers. The VRUs are connected to flare stack S/V 241-01, the VRU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes leaks from process equipment including one (1) compressor (identified as J-3E located at

VRU-100), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system. The facility may ~~also~~ include insignificant activities listed in Section A.4 of this permit.

(2) As part of the VRU 100/200 Whiting Atmospheric Relief Project (WARP), permitted in 2008, the pressure relief discharges that vented to the existing VRU 100/200 vent stack are being re-routed to the VRU flare.

(f) **(A)** The Vapor Recovery Unit 300 (VRU 300), identified as Unit ID 150. Light ends and naphtha are separated in the VRU using a series of distillation towers. This unit is connected to flare stack S/V 241-01, the VRU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) off-gas knock out drum (D-400) which exhausts to flare stack S/V 241-01.

(2) Leaks from process equipment, including two (2) compressors (identified as K-340 and K-351), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation system.

(B) Vapor Recovery Unit VRU 400 for the New Coker (#2 Coker) to be installed as part of the CXHO Project.

(g) The Alkylation Unit, identified as Unit ID 140, combines isobutane with butylenes and propylenes to produce alkylate. The alkylate, a high octane naphtha, is blended into gasoline. This unit was built in 1961 and expanded in 1989. This unit is connected to flare stack S/V 140-01, the Alky Flare, to control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) off gas knock-out drum (D-22), which exhausts to flare stacks S/V 140-01.

(2) One (1) spent acid stripper drum (D-13), which exhausts to flare stacks S/V 140-01.

(3) One (1) spent caustic drum (D-32), which exhausts to flare stacks S/V 140-01.

(4) Leaks from process equipment, including two (2) compressors (identified as K-1 and K-1A), valves, pumps, pressure relief devices, sampling connection systems, and instrumentation system.

(h) The Propylene Concentration Unit (PCU), identified as Unit ID 145, purifies propylene for sale to chemical plants and eventual manufacture into polypropylene plastic. This unit also has a treating system, which purifies propane. This unit is connected to flare stack S/V 140-01 (the Alky Flare). The flare controls VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes a caustic degassing drum (D-100) that is vented to flare stack S/V 140-01 and leaks from process equipment, including one compressor (identified as k-104), pumps, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation system. This facility may include insignificant activities listed in Section A.4 of this permit.

(i) The Isomerization Unit (ISOM), identified as Unit ID 210, was constructed in 1985 as a conversion of the No.2 Ultraformer. The Isomerization process converts low octane naphtha into high octane gasoline blending components. This unit is connected to flare stack S/V 220-04, the UIU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. **As part of the CXHO project, the ISOM heater H-1 will be modified by replacing several burners with larger burners, with rated capacity remaining at 190 MMBTU/hr.** The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit.

(1) One (1) natural gas, refinery gas, or liquified petroleum gas-fired Process Heater H-1, **modified as part of CXHO,** rated at 190 MMBtu/hr and vented to stack S/V 210-01.

(2) One (1) Flare Knock-out Drum (D-18) with emissions vented to vessel D-24, which exhausts to flare stack S/V 220-04.

(3) Leaks from process equipment, including one (1) compressor (identified as K1), pumps, valves, process drains and pressure relief devices.

(j) The Aromatic Recovery Unit (ARU), identified as Unit ID 242, consists of the ARU 200 section and the ARU 300 section. The primary function is to remove light ends from naphtha to obtain a more desirable reforming feed. Its secondary function is to separate xylene, a chemical feedstock, from the Ultraformer product. The ARU utilizes a series of distillation towers to purify reformer feed and another set of towers to separate chemical feedstocks. The ARU includes the following process units and may ~~also~~ include insignificant activities listed in Section A.4 of this permit.

(1) The following process heaters, which are fired with refinery gas, natural gas or liquified petroleum gas.

Heater Identification	Construction Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-200A	1978	249.5	242-01	None
F-200B	1978	249.5	242-02	None

(2) The ARU is connected to the 4UF flare stack, S/V 224-06. The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(3) Leaks from process equipment.

(k) The Blending Oil Unit (BOU), identified as Unit ID 250, uses hydrogen to convert sulfur to hydrogen sulfide and remove it from distillate and gas oil streams to meet product specifications. The hydrogen sulfide is sent to the Claus Trains for further processing. **As part of the CXHO Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr.** The facility includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) One process Furnace F-401, constructed in1972, **and modified as part of CXHO,** which vents to stack ID S/V250-01. The furnace is rated at 35 million Btu and is fired by natural gas, refinery gas or liquid petroleum gas.

(2) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(l) No. 2 Treatment Plant, identified as unit 601, removes disagreeable odors from various naphtha streams using a catalytic process. This facility has only fugitive emissions and/or other emissions that are considered insignificant.

(m) No. 4 Treatment Plant, identified as unit 602, removes disagreeable odors from various naphtha and distillate streams using a catalytic process. This facility has only fugitive emissions and/or other emissions that are considered insignificant. **The No. 4 Treatment Plant will be decommissioned as part of the CXHO project.**

(n) Butane, Propane and Propylene Storage and Loading Facilities, identified as Unit ID 604, includes the following sources of emissions and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) One (1) butane storage cavern located in South Tank Field.

(2) Seven (7) pressurized butane storage spheres located southwest of the main Refinery near the J&L Tank Field with a capacity of 1,050,000 gallons each.

(3) Propane (LPG) storage caverns and above-grade pressurized storage vessels located near the J&L Tank Field.

(4) Propane (LPG) railcar loading facilities located near the J&L Tank Field. These can also be used for loading butane into railcars.

(5) Pressurized polymer grade propylene (PGP) and refinery grade propylene (RGP) storage vessels located at the northeast end of the Refinery.

(6) Propylene truck and railcar loading facilities located at the north east end of the Refinery, with emissions vented to the PIB flare, which is owned and operated by INEOS USA, LLC (Plant I.D. 089-00076).

(7) One (1) LPG loading area flare stack having stack number S/V 604-01, installed in 1986, which is used as a safety device which burns any vented gases that might result from relieving pressure on equipment.

(8) Leaks from process equipment.

(o) The No.3 Ultraformer Unit (No. 3 UF), identified as Unit ID 220, commissioned in 1958**. The majority of the unit was shutdown in March 2007, including the H-1, H-2 and F-7 heaters, catalyst-filled reactors and the internal scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation steps of the regeneration process. The unit consists of the C-2 Splitter Tower, the D-18 flare gas separator, D-24 knock-out drum and associated piping.** ~~, used to upgrade low-octane naphtha to gasoline blending material and chemical feedstocks. The reforming section of a series of process furnaces and catalyst-filled reactors in which the naphtha is heated and converted from straight chain to aromatic compounds. The reactor products are separated by distillation for further processing or blending into gasoline.~~ The No. 3 Ultraformer is connected to flare stack S/V 220-04, the UIU flare, to control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance and reactor regenerations. The No.3 Ultraformer includes the following sources of emissions and may ~~also~~ include insignificant activities listed in Section A.4 of this permit.

~~(1) Three (3) process heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:~~

~~Heater Identification~~	~~Maximum Heat Input Capacity (MMBtu/hr)~~	~~Stack Exhausted To~~	~~Emission Controls~~
~~H-1~~	~~240~~	~~220-01~~	~~None~~
~~H-2~~	~~185~~	~~220-02~~	~~None~~
~~F-7~~	~~23~~	~~220-03~~	~~None~~
~~Regeneration Furnace~~	~~Not in service~~	~~Not in service~~	~~None~~

~~(2)~~**(1)** One (1) flare gas separator (D-18) with emissions vented to vessel D-24, which exhausts to flare stack S/V 220-04.

~~(3) Five (5) catalyst-filled reactors, which are vented to flare stack S/V 220-04 during the initial catalyst depressuring and catalyst purging steps of the regeneration process.~~

~~(4) One (1) internal scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation steps of the regeneration process, which removes HAP emissions.~~

~~(5)~~**(2)** Leaks from process equipment, including one (1) compressor (identified as K-1), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(p) The No.4 Ultraformer Unit (no. 4 UF), identified as Unit ID 224, built in 1972, upgrades low-octane naphtha to gasoline blending material and chemical feedstocks. **The front-end of the unit is a desulfurization section.** The reforming section consists of a series of process furnaces and catalyst-filled reactors in which the naphtha is heated and converted from straight chain to aromatic compounds. The reactor products are separated by distillation for further processing or blending into gasoline. **A new reactor will be installed as part of the CXHO project** ~~The No.4 Ultraformer has a regeneration furnace which heats regeneration gas for use in catalyst regenerating. Reactors are taken off-Line and vented to the atmosphere during regeneration.~~ The No. 4 Ultraformer includes the following sources of emissions and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Nine (9) process heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-1	68	224-01	None
F-8A	163	224-01	None
F-8B	163	224-01	None
F-2	286	224-02	None
F-3	242	224-03	None
F-4	137	224-03	None
F-5	99	224-04	None
F-6	49	224-04	None
F-7	52	224-05	None

(2) One (1) flare (identified as the 4UF flare), exhausting at stack S/V 224-06. The 4UF flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance, and reactor regenerations.

(3) Six (6) catalyst-filled reactors, which are vented to flare stack S/V 224-06 during the initial catalyst depressuring and catalyst purging steps of the regeneration process.

(4) Leaks from process equipment, including two (2) compressors (identified as K-1 and K-7), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(5) One (1) caustic scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation steps of the regeneration process, which removes HAP emissions. The scrubber system includes:

(A) One (1) caustic scrubber exhausting to stack 224-07;

(B) One (1) carbon adsorption system used to treat waste scrubber liquor prior to disposal; and

(C) Caustic feed unloading, storage, and transfer equipment.

(q) The Hydrogen Unit (HU), identified as Unit ID 698, commissioned in 1993, produces 99+% pure hydrogen needed for the refinery hydrotreating processes. The HU produces high purity hydrogen by reacting steam with methane. The reaction is carried out by heating the mixture in a furnace and reacting it in the presence of a catalyst. The HU includes the following sources of emissions and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) One (1) natural gas, refinery gas or liquified petroleum gas fired B-501 Process Heater rated at 366.3 MMBtu/hr, which exhausts at stack S/V 698-01. The Process Heater is equipped with low-NO_x burners.

(2) One (1) DDU Flare exhausting at stack S/V 698-02, burning natural gas as the pilot gas, used to control VOC emissions during emergency situations, unit startups and shutdowns and depressuring equipment for maintenance.

(3) Leaks from process equipment.

(r) The Distillate Desulfurizer Unit (DDU), identified as Unit ID 700, commissioned in 1993, removes sulfur from petroleum distillates. Distillate feed is mixed with hydrogen, heated in process furnaces and passed over a catalyst bed to convert sulfur compounds to H_2S. The DDU includes the following emissions sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Process Heater WB-301, rated at 64.8 MMBtu/hr and exhausting to stack S/V 700-01. The Process Heater is equipped with low-NO_x burners and burns natural gas, refinery gas, or liquified petroleum gas.

(2) Process Heater WB-302, rated at 83.7 MMBtu/hr and having stack ID S/V 700-02. The Process Heater is equipped with low-NO_x burners and burns natural gas, refinery gas, or liquified petroleum gas

(3) Leaks from process equipment.

(4) The Distillate Desulfurization Unit is connected to the DDU Flare System. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns and depressuring equipment for maintenance.

(s) The Cat Feed Hydrotreating Unit (CFHU), identified as Unit ID 171, built in 1982, removes sulfur from and improves the quality of gas oil feed to the Fluidized Cracking Units. The No. 4 Ultraformer Flare Stack, S/V 224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The CFHU is connected to the No. 4 Ultraformer flare stack. The flare is used to control VOC emissions, unit startups and shutdowns, and preparation of equipment for maintenance. The CFHU includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Three (3) process heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-801 A/B	66.5	171-01	low-NO_x burners
F-801C	60.0	171-02	ultra low-NO_x burners

(2) Leaks from process equipment.

(t) The Catalytic Refining Unit (CRU), identified as Unit ID 201, which removes sulfur from petroleum naphthas and distillates. Naphtha or distillate feed is mixed with hydrogen, heated in process furnaces and passed over a catalyst bed inside one of two reactor trains, identified as D-114 and D-105, to convert sulfur compounds to hydrogen sulfide. Hydrogen sulfide is subsequently removed from the product by distillation followed by scrubbing with an amine. The CRU includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Two (2) heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-101	72	201-01	Low-NO_x Burners
F-102A	60	201-02	Low-NO_x Burners

(2) The CRU is connected to the UIU flare stack, S/V 220-04. The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(3) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

Main Operating Scenario:
The CRU operates as a naphtha hydrotreater. Maximum production under this scenario is 27,000 barrels per day.

Alternative Operating Scenario:
The CRU operates as a distillate hydrotreater. Maximum production under this scenario is 40,000 barrels per day.

(u) The Fluidized Catalytic Cracking Unit (FCU) 500, constructed in 1945, identified as Unit ID 230 and rated at 115,000 barrels per day. This facility converts hydrocarbons that boil above 500 ^{o}F into lower molecular weight products, which include gasoline and LPG. The cracking takes place as the gas oil and catalyst stream mix in the reactor. This process results in the catalyst being coated with coke, which is subsequently burned off in a regenerator. The FCU 500 includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) One (1) catalyst regenerator. Flue gas from the regenerator passes through an ammonia injection system, a waste heat recovery unit that generates steam, an Electrostatic Precipitator for particulate matter control, and is exhausted through stack S/V 230-01. The ammonia injection system includes aqueous ammonia injection and handling equipment. Aqueous ammonia is transferred from the FCU 600 SCR system's storage tanks.

(2) Three (3) catalyst storage bins, one each for spent, equilibrium, and fresh catalyst. Particulate emissions from the spent catalyst storage bin, identified as Bin F-52, are controlled by one (1) cyclone, which exhausts to stack S/V 230-03.

(3) One (1) flare exhaust at stack S/V 241-01 (VRU Flare). The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including two (2) compressors (identified as J-3D and J-3G), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system.

(5) As part of the FCU 500 WARP, permitted in 2008, the FCU 500 blowdown stack will be shutdown and the pressure relief discharges that vent to the blowdown stack will be re-routed to the VRU flare.

(6) The FCU 500 turnaround (TAR) project, permitted in 2008, for the repair or replacement of the power recovery turbine, and the air ring for the catalyst regenerator. The increases in emissions from FCU 500 TAR are already accounted for as CXHO project related emissions increases.

(v) The Fluidized Catalytic Cracking Unit (FCU) 600, constructed in 1946, identified as Unit ID 240 and rated at 80,000 barrels per day. This facility converts hydrocarbons that boil above 500 ^{o}F into lower molecular weight products, which include gasoline and LPG. The cracking takes place as the gas oil and catalyst stream mix in the reactor. This process results in the catalyst being coated with coke, which is subsequently burned off in a regenerator. The FCU 600 includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) One (1) catalyst regenerator. Flue gas from the regenerator passes through a waste heat recovery unit, which generates steam and an Electrostatic Precipitator for particulate matter control. The flue gas is then directed to a selective catalytic reduction (SCR) system, which chemically reduces nitrogen oxide emissions by reaction with injected ammonia, and is exhausted through stack S/V 240-01.

(2) Two catalyst storage bins, one each for equilibrium and fresh catalyst. (Spent catalyst is stored in Bin F-52, which is associated with FCU 500.)

(3) One (1) flare exhausting at stack ID S/V 230-02 (FCU Flare). The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including two (2) wet gas compressors (identified as J-3Dand J-3E), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system.

(5) As part of the FCU 600 WARP, permitted in 2008, to shutdown the existing FCU 600 blowdown stack and the pressure relief discharges that were vented to the blowdown stack will be re-routed to the FCU flare.

(6) The FCU 600 turnaround (TAR) project, permitted in 2008, for the repair or replacement of the main fractionator overhead condensers, the slurry and pump around system, unit pump replacement, FCU flare tip replacement, and additional controls to reduce plugging on the SCR. The increases in emissions from FCU 600 TAR are already accounted for as CXHO project related emissions increases.

(w) A portion of No. 1 Stanolind Power Station (SPS) constructed in 1928 and identified as Unit ID 501. The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas, are NOx budget units:

(1) The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Boiler Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
#3 Boiler	265	501-01	None
#4 Boiler	265	501-01	None
#5 Boiler	265	501-02	None
#6 Boiler	265	501-02	None
#7 Boiler	265	501-02	None

Note: The boilers in No. 1 Stanolind Power Station are scheduled to be shut down as part of the Consent Decree 2:96 CV 095 RL.

(2) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(x) A portion of No. 3 Stanolind Power Station (SPS) constructed as listed below and identified as Unit ID 503. The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas, are NOx budget units:

(1) The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Boiler Identification	Installation Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
#1 Boiler	1948	575	503-01	**(current)** low-NO_x burners, an induced flue gas recirculation (IFGR) system, and an over fired air (OFA) system
#2 Boiler	1948	575	503-02	
#3 Boiler	1951	575	503-03	
#4 Boiler	1951	575	503-04	
#6 Boiler	1953	575	503-05	**After CXHO: The low-NOx burners, IFGR and OFA will be replaced by conventional burners and a Selective Catalytic Reduction (SCR) system on Boilers # 1, 2, 3, 4, 6**

(2) Five (5) direct-fired duct burners, permitted in 2008, rated at 41 mmBTU/hr each, equipped with low NOx burners and controlled by a Selective Catalytic Reduction (SCR) system.

~~(2)~~ **(3)** Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(y) **Hazardous Waste Treatment System:**

~~Fluid Bed Incinerator (FBI), identified as Unit ID 510, equipped with a wet venturi scrubber, wet electrostatic precipitator (WESP) and a carbon bed absorber. This is a refinery pollution control system for hazardous waste materials and regulated under the Resource Conservation and Recovery Act (RCRA) and the Hazardous Waste Combustion MACT Standards. It is designed to treat API separator sludge, DAF skimmings and biological solids from the waste water treatment plant. The WESP and carbon bed absorber were installed in 2003. This facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:~~

~~(1) The following incinerator fired by No.2 fuel oil:~~

~~Incinerator~~	~~Construction Date~~	~~Maximum Heat Release Capacity~~	~~Stack Exhausted to~~	~~Control Devices~~
~~FBI~~	~~1972~~	~~82 MMBtu/hr~~	~~510-01~~	~~Wet venturi scrubber with demisting vanes for PM control~~ ~~Wet Electrostatic Precipitator~~ ~~Carbon Bed Adsorber~~

Dewatering and thermal desorption system for processing sludge, permitted in 2008, including dissolved air flotation skimmimgs (DAF) and API oil/water separator sludge, The dewatering system will be equipped with a wet scrubber and carbon canister system and the thermal desorption unit will be equipped with a vapor recovery to optimize absorption of hydrocarbons. The feed rate capacities at the dewatering system and thermal desorption systems are 22,500 tons of feed per year and 9,000 dry tons of solids per year, respectively. This facility includes the following emission sources and may include insignificant activities listed in Section A.4 of the permit:

(1) Two (2) centrifuges;

(2) Two (2) sludge surge tanks;

(3) One (1) oil/water mixture surge tank;

(4) One (1) enclosed auger transfer system;

(5) One (1) vapor recovery system on the thermal desorption unit including: an oil condensing/scrubbing system, a water condensing/scrubbing system, and an oil water separator. Uncondensed vapors from this system are routed to the two (2) diesel fired burners for destruction of VOCs.

Insignificant Activity:

(6) Two (2) diesel fired burners rated at 4 mmBTU/hr each, for the thermal desorption system.

(z) Wastewater Treatment Plant (WWTP), identified as Unit ID 544. This facility treats the water used in the refining process that comes into contact with oil or chemicals. In the first step, the heavier solids are removed at the inlet to the WWTP and the floating oil is skimmed from the surface of the wastewater in the API separator boxes. The oil is then recycled back to the refinery. The water is then aerated in the Air Flotation Unit where additional solid impurities are floated and skimmed. Thereafter, it moves to the Activated Sludge Plant where special bacteria digest the remaining contaminants. The water then passes through a clarifier and then eight (8) final filters before being returned to Lake Michigan. This facility includes the following emission sources and may ~~also~~ include insignificant activities listed in section A.4 of this permit:

(1) The following units are equipped with closed vent systems: oil sump P-1, oil sump P-2, and Diffused Air Floatation (DAF) Secondary Boxes, which vent to a biofilter and carbon canisters; Tank 569 is equipped with a conservation vent.

(2) The following units are equipped with a fixed-roof or floating roof: Interceptor Box, Diversion Box (from Tank 5051 to DAF), DAF Flash Mixer, DAF Influent Channel, DAF Effluent Channel, DAF Primary Boxes, and DAF Sump.

(3) One (1) storage tank (identified as Tank 5051) having a maximum storage capacity of 10,000,000 gallons, constructed in 1988 and equipped with an external floating roof.

(4) One (1) storage tank (identified as Tank 5050) having a maximum storage capacity of 10,000,000 gallons, constructed in 1988. This tank is used for storm event and upset impoundments.

(5) Seven (7) oil-water/solids separator units enclosed with a fixed-roof: Bar Screen, #7 API Separator Fixed Cover, #7 API Separator Primary Inlet, #7 API Separator Secondary Inlet, #7 API Separator Secondary Outlet, #7 API Separator Inlet Channel Section, and #7 API Separator Gear Boxes.

(6) One (1) storage tank (identified as Tank 5052) having a maximum storage capacity of 11,676,000 gallons, to be constructed as part of the CXHO Project. This tank will be used as a stormwater equalization tank and is equipped with an external floating roof.

(7) A brine treatment system with seven (7) wastewater tanks with vertical fixed roofs, constructed as part of CXHO project, identified as:

(A) TK-105A, with a storage capacity of 867,180 gallons;
(B) TK-105B, with a storage capacity of 867,180 gallons;
(C) TK-101, with a storage capacity of 66,096 gallons;
(D) TK-102, with a storage capacity of 66,096 gallons;
(E) TK-103, with a storage capacity of 66,096 gallons;
(F) TK-104A, with a storage capacity of 89,943 gallons; and
(G) TK-104B, with a storage capacity of 89,943 gallons.

(aa) Oil Movements, identified as Unit 640. This facility is used to store, blend, and ship products. Gasoline blending components are custom blended into various grades of gasoline. Additive and other compounds are blended into the products to give them their unique characteristics. Furnace oil and other distillates are also blended using components from process units or storage. Crude oil and feedstocks for process units and products are also stored at this location. Product loading operations include the pipeline and railcar racks. This facility includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) One (1) internal floating roof storage tank identified as 3730, storing ethanol, constructed in 1955, with a maximum storage capacity of 1,050,721 gallons.

(2) Ten (10) external floating roof storage tanks storing petroleum hydrocarbon with vapor pressure less than 15 psia, comprising the following tanks:

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3529	1948	858,000
3637	1956 **permitted in 2008 for reconstruction**	6,353,000
3901	1956	1,906,000
3902	1956	1,906,000
3915	1980	6,353,460
3916	1980	13,666,998
3917	1980	25,413,839
3918	1980	13,666,998
3919	1980	13,666,998
3920	1980	13,666,998

(3) Sixty-seven (67) internal floating roof storage tanks, storing petroleum hydrocarbon with vapor pressure less than 15 psia, comprising the following tanks:

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3474	1992	3,734,422
3475	1994	3,865,445
3476	1984	3,085,016
3477	1971	4,066,214
3480	1982	4,026,505
3482	1972	169,426
3483	1924	3,382,264
3484	1996	3,865,445
3486	1979	4,026,505
3487	1980	4,026,505
3488	1994	3,865,445
3489	1996	3,865,445

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3492	1925/1971	3,382,000
3493	1995	3,865,445
3510	1949	4,235,640
3511	1973	4,066,214
3512	1958	4,066,214
3513	1971	4,066,214
3514	1984	4,066,214
3525	1981	4,026,505
3526	1943/1979	4,026,505
3527	1991	3,382,264
3528	1993	3,865,445
3531	1948/1997	857,717
3532	1953	868,306
3533	1953	4,235,640
3534	1955/1973	71,000
3549	1993	588,283
3553	1981	5,070,343
3554	1981	5,070,343
3558	1972/1986	376,501
3600	1993	847,128
3601	1977	3,702,020
3602	1979	3,856,271
3604	1980	3,856,271
3605	1977	3,702,000
3622	1993	3,865,445
3624	1932	3,382,264
3629	1992	3,865,445
3631	1944	3,382,000
3633	1950	5,282,000
3635	1954	5,070,000

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3639	1956	6,353,460
3641	1956	6,353,460
3701	1943/1993	3,382,264
3702	1943/1982/1997	3,382,264
3703	1944/1982	3,382,264
3704	1944/1980	3,382,264
3705	1944	3,382,264
3706	1944	3,382,264
3707	1944/2000	3,382,264
3708	1943	853,895
3709	1943	825,434
3710	1943	2,059,000
3715	1945/1987/1998	3,382,264
3716	1996	3,865,445
3727	1948	857,717
3728	1970	857,717
3860	1993	211,782
3900	1956/2005	1,906,000
3904	1956/1986	3,388,512
3905	1956	6,353,460
3907	1956/1996	3,388,512
3909	1956	3,388,512
3911	1956/1986	3,388,512
3912	1956	6,353,460
3914	1956	3,388,512

(4) Miscellaneous Storage tanks including the following:

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	Vapor Pressure of Liquid (psia)
D-424	4ULTRAFORMER	Methanol Tank	--	3,744	<0.5
F-011	4B TREATER	Casper Dewaterer	1949	17,624	<0.5

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	Vapor Pressure of Liquid (psia)
TK-0563	INCINERATOR	Aux. Fuel Oil	1971	49,378	<0.5
TK-3228	CRUDE STA	Decanted Oil	1948	596,570	<0.5
TK-3234	CRUDE STA	Decanted Oil	1940	858,298	<0.5
TK-3464	BERRY LAKE	Decanted Oil	1957	2,705,472	<0.5
TK-3465	BERRY LAKE	Plant Fuel	1973	3,413,088	<0.5
TK-3468	BERRY LAKE	TGO	1958	3,381,840	<0.5
TK-3491	SO. TK FLD.	Lsho	1992	3,876,768	<0.5
TK-3496	SO. TK FLD.	Distillate	1992	3,876,768	<0.5
TK-3498	SO. TK FLD.	Amoco Premier Diesel [Future Lsfo]	1929	3,373,413	<0.5
TK-3499	SO. TK FLD.	Amoco Premier Diesel [Future Lsfo]	1996	3,870,720	<0.5
TK-3500	SO. TK FLD.	Furnace Oil [Future Hmd]	1996	3,870,720	<0.5
TK-3505	SO. ANNEX	Heater Oil	1949	4,254,768	<0.5
TK-3509	SO. TK FLD.	Furnace Oil	1948	3,381,840	<0.5
TK-3546	SO. TK FLD.	Bronze Dye	1962	16,800	<0.5
TK-3547	SO. TK FLD.	Purple Dye	1962	16,800	<0.5
TK-3548	SO. TK FLD.	Isonox 133	1962	16,800	<0.5
TK3567	--	--	--	17,000	<0.5
TK-3569	MARINE DOCK	DCO	1981	4,796,064	<0.5
TK-3571	MARINE DOCK	HS Resid/Black Oil	1971	5,539,968	>0.5 and <0.75
TK-3572	MARINE DOCK	HS Resid/Black Oil	1971	5,539,968	>0.5 and <0.75
TK-3606	STIGLITZ PK.	Amoco Jet Fuel A [New 1996]	1996	3,701,376	<0.5
TK-3607	STIGLITZ PK.	Amoco Jet Fuel A	1993	3,729,600	<0.5
TK-3609	STIGLITZ PK.	HS Resid	1973	9,652,608	<0.5
TK-3610	STIGLITZ PK.	HS Resid	1973	9,652,608	<0.5
TK-3611	STIGLITZ PK.	HS Resid	1973	8,513,400	<0.5
TK-3613	STIGLITZ PK.	HS Resid	1992	3,876,768	<0.5
TK-3711	IND. TK FLD.	Lcco	1993	2,818,368	<0.5
TK-3712	IND. TK FLD.	Lcco	1945	3,357,600	<0.5
TK-3714	IND. TK FLD.	Distillate/Gas Oil	1999	3,852,576	<0.5
TK-3717	IND. TK FLD.	Fcu Feed Mixed	1943	3,263,190	<0.5
TK-3718	IND. TK FLD.	Gas Oil	1996	3,871,379	<0.5
TK-3719	IND. TK FLD.	Gas Oil	1943	3,357,600	<0.5
TK-3720	IND. TK FLD.	Gas Oil	1946	3,357,600	<0.5
TK-3721	IND. TK FLD.	Gas Oil	1946	3,357,600	<0.5
TK-3722	IND. TK FLD.	Gas Oil	1952	4,227,300	<0.5
TK-3723	IND. TK FLD.	Gas Oil	1954	3,386,880	<0.5
TK-3726	IND. TK FLD.	Amoco Jet Fuel A	1948	857,356	<0.5
TK-3733	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,383,520	<0.5
TK-3734	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,383,520	>0.5 and <0.75
TK-3735	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,411,072	<0.5
TK-3867	SO. TK FLD.	Stadis 450	1967	17,640	<0.5
TK-3868	SO. TK FLD.	Amogard	1953	17,640	>0.5 and <0.75
TK-3869	SO. TK FLD.	Pour	1956	23,436	<0.5

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	Vapor Pressure of Liquid (psia)
		Depressant			
TK-3872	CRUDE STA	Used Motor Oil	1985	15,120	<0.5
TK3876	South TF	Cetane Improver	1993	14,381	<0.5
TK-3906	J&L TK FLD.	Lsfo	1956	3,381,840	>0.5 and <0.75
TK-3908	J&L TK FLD.	Amoco Premier Diesel	1956	3,381,840	<0.5
TK-3910	J&L TK FLD.	Furnace Oil [Hs]	1956	3,381,840	<0.5
TK-3913	J&L TK FLD.	Furnace Oil [Ls]	1956	3,402,977	<0.5
TK-6078	ASPHALT	HS Resid/Black Oil	1948	1,931,000	<0.5
TK-6113	ASPHALT	Paving Base	1944	810,600	<0.5
TK-6114	ASPHALT	Paving Base	1944	810,600	<0.5
TK-6125		Paving Base	1998	3108932	<0.5
TK-6126		Paving Base	1999	3,108,000	<0.5
TK-6127		Paving Base	2000	3,108,000	<0.5
TK-6128		Paving Base	1971	3,225,600	<0.5
TK-6129		Paving Base	2005	3,108,000	<0.5
TK-6148		Paving Base	1948	3,108,000	<0.5
TK-6149		Paving Base	1948	3,108,000	<0.5
TK-6150		HS Resid	1986	810,600	<0.5
TK-6153		HS Resid	1979	1,386,000	<0.5
TK-6248	ASPHALT	Low Sul Resid	1973	7,218,928	<0.5
TK-6249	ASPHALT	Low Sul Resid	1973	7,218,928	<0.5
TK-6250	ASPHALT	HS Resid	1971	7,218,928	<0.5
TK-6251	ASPHALT	Paving Base	1971	7,218,928	<0.5
TK-6252	ASPHALT	HS Resid	1972	7,215,268	<0.5
TK-6253	ASPHALT	Paving Base	1971	7,218,928	<0.5
TK-6261	ASPHALT	HS Resid	1973	451,183	<0.5
TK-6262	ASPHALT	HS Resid	1972	451,183	<0.5
~~BT-002~~	~~MARINE DOCK~~	~~Out of Service~~	~~1968~~	~~874,944~~	~~--~~
TK-0559	ASU	Out of Service	1989	146,869	--
TK-0560	ASU	Out of Service	1948	587,477	--
TK-0568		Out of Service	Before 1973	--	--
TK-3167		Out of Service	1926	3,361,114	--
TK-3168		Out of Service	1926	1,931,170	--
TK-3169		Out of Service	1926	3,361,114	--
TK-3232	CRUDE STA	Out of Service	1940	857,356	--
TK-3259	CRUDE STA	Out of Service	1951	846,720	--
TK-3260	CRUDE STA	Out of Service	1930	375,986	--
TK-3279	MARINE DOCK	Out of Service	1951	85,302	--
TK-3309	CRUDE STA	Out of Service	NA	7,050	--
TK-3373		Out of Service	--	--	--
TK-3471	SO. TK FLD.	Out of Service	1973	7,050	--
TK-3485	SO. TK FLD.	Out of Service	1924	3,373,413	--
TK-3494	SO. TK FLD.	Out of Service	1926	3,373,413	--
TK-3497	SO. TK FLD.	Out of Service	1926	3,373,413	--
TK-3506	SO. ANNEX	Out of Service	1936	3,373,413	--
TK-3507	SO. ANNEX	Out of Service	1936	3,373,413	--
TK-3508	SO. ANNEX	Out of Service	1936	3,366,720	--
TK-3603	STIGLITZ PK.	Out of Service	1922	3,084,480	--
TK-3608	STIGLITZ PK.	Out of Service	1954	3,849,300	--
TK-3713	IND. TK FLD.	Out of Service	1944	3,357,600	--
TK-3903	J&L TK FLD.	Out of Service	1956	3,381,840	--
TK-6222		Out of Service	--	3,000	--
TK-6223		Out of Service	--	211,400	--

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	Vapor Pressure of Liquid (psia)
TK-6224		Out of Service	--	211,400	--
W-306	MWTP	Out of Service	--	--	--

"--" - no data provided.

(5) One (1) oil-water separator identified as the J&L Separator.

(6) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(bb) The general facility remediation system, identified as Unit 999. Remediation includes multiple well point systems. The well point system extracts groundwater, which may have a small hydrocarbon fraction. Depending on the VOC concentration, emissions generated by these systems may be routed to the atmosphere or to a thermal oxidizer. Additionally, one or more systems may route to the same oxidizer. Each system uses a common horizontal vacuum header to collect groundwater through a series of wells, and any entrained air is discharged through a vent at the vacuum pump. Recovered groundwater is then transferred to either a vapor/liquid separation tank or directly to another unit for further processing/treatment. Remediation includes the following emission sources and may ~~also~~ include insignificant activities listed in section A.4 of this permit.

(1) The following well point systems:

Facility I.D.	Installation Date	S/V I.D.	Normal Venting	Controls
J-136	1993	999-01	Vented Separately	Uncontrolled
J-137	1992	999-02	Vented Separately	Uncontrolled
J-138	1991 Extension 1994	999-03	J-138, J-139 and J-140 are vented with D-138 (vapor/liquid separation tank)	0.685 MMBtu per hour Thermal Oxidizer ITF
J-139	1981	999-04		
J-140	1981	999-05		
J-141	1988 Extension 1993	999-06	Vented Separately	Uncontrolled
J-156	1968-1970	999-07	Vented Separately	Uncontrolled
J-157	1968-1970	999-08	Vented Separately	Uncontrolled
J-158	1968-1970	999-10	J-158, & J-159 vents are common	Electric Catalytic Oxidizer 600 ^{o}F min. temp., @ 1,000 scfm
J-159	1968-1970	999-11		

Facility I.D.	Installation Date	S/V I.D.	Normal Venting	Controls
J-160	1968-1970 Extension 1994	999-12	Vented Separately	Electric Catalytic Oxidizer, 600 ^{o}F min. temp., @ 1,000 acfm
J-161	1992	999-13	Vented Separately	0.685 MMBtu per hour Thermal Oxidizer BLTF
J-162	1996	999-14	Vented Separately	Uncontrolled
J-163	1996	999-15	Vented Separately	Uncontrolled

(cc) The Mechanical Shop, identified as Unit 693. The Mechanical Shop includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Two (2) Heat Treat Furnaces that are considered insignificant sources.

(2) Leaks from facility fuel gas lines.

(dd) One bulk truck loading facility, identified as the Marketing Terminal, and consisting of one (1) truck loading rack, constructed in 1972 and modified in 1992, comprised of 7 bays used for loading gasoline products and fuel oil. Four bays are dedicated to loading distillates, while the other three bays are dedicated to loading gasoline products. The maximum throughput for the truck loading facility is 1,103,760,000 gallons per year. Emissions of volatile organic compounds are controlled using a vapor combustion unit (identified as VCU).

(ee) **Cooling Towers** ~~constructed prior to 1995~~**, including the following:**

(1) One (1) cooling tower (identified as Cooling Tower No.6), constructed in 1996, with a maximum capacity of 20,000 gallons of water per minute. Cooling Tower No.6 is located at the No.12 Pipestill.

(2) Cooling Towers (constructed prior to 1980), with controls installed as part of the CXHO project:

Cooling Tower	Recirculation Rate/Make-up rate (gallons/minute)	Control Devices
Cooling Tower 2*	**50,000/1,285**	**high efficiency liquid drift eliminators**
Cooling Tower 3	**90,000/1,571**	**high efficiency liquid drift eliminators**
Cooling Tower 4	**44,000/1,085**	**high efficiency liquid drift eliminators**

*** Half of the Cooling Tower 2 modules were controlled prior to the CXHO Project. Contemporaneous to the CXHO Project the other modules will be controlled with high efficiency drift eliminators.**

(3) Cooling Towers to be installed as part of the CXHO project:

Cooling Tower	Recirculation Rate/Make-up rate (gallons/minute)	Control Devices
Cooling Tower 7	**21,000/451**	**high efficiency liquid drift eliminators**
Cooling Tower 8	**90,000/2956**	**high efficiency liquid drift eliminators**

(ff) One (1) Asphalt Facility used to store, blend and transfer asphalt products. The facility has six blenders used for loading asphalt into railcars and trucks. Process heaters are used to keep certain tanks at the proper temperature for shipping. This facility includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) The following two (2) process heaters:

Process Heater ID	Heat Input Capacity (MMBtu/hr)	Fuel	Control Device
F-1 Asphalt Heater	12	Natural gas	none
F-2 Steiglitz Park Heater	28	Natural gas	none

(2) The following seven (7) asphalt storage tanks used to store volatile organic liquids that have a vapor pressure less than 0.75 psi:

Identification	Storage Capacity (gallons)	Year Constructed
125	3,108,000	1998
126	3,108,000	1999
127	3,108,000	2000
129	3,108,000	2003
150	1,386,000	1986
569	5,544,000	1981
613	8,866,200	1992

(3) The following twenty-five (25) asphalt storage tanks used to store volatile organic liquids that have a vapor pressure less than 0.5 psi.

Identification	Storage Capacity (gallons)	Year Constructed
78	1,814,400	1947
113	810,600	1944
114	810,600	1944
128	3,225,600	1971
148	810,600	1948
149	810,600	1948
153	932,400	1979
222	210,000	1955
223	210,000	1955
224	210,000	1955
225	361,200	1950
248	6,967,800	1973
249	6,967,800	1973
250	6,967,800	1971

Identification	Storage Capacity (gallons)	Year Constructed
251	6,967,800	1971
252	6,967,800	1972
253	6,967,800	1971
261	441,000	1973
262	441,000	1972
468	3,108,000	1956
571	5,040,000	1971
572	5,040,000	1971
609	5,649,000	1973
611	8,513,400	1973

(4) The following twenty-two (22) heated vertical storage tanks, each approved for construction in 2007, each with a fixed cone roof, and each in heavy liquid service, storing volatile organic liquids that have a vapor pressure less than 0.0435 psia, and exhausting to the atmosphere or to a biofilter system for odor and opacity control:

Tank ID	Liquid Stored	Date Approved for Construction	Tank Storage Capacity (gallons)	Maximum Throughput (gallons/yr)	Exhaust ID
TK-3573	Trim Gas Oil	2007	966,000	20,160,000	TK-3573
TK-SP-1	Residual Oil and/or Asphalt	2007	14,154,000	141,120,000	biofilter
TK-SP-2	Residual Oil and/or Asphalt	2007	14,154,000	141,120,000	biofilter
TK-SP-3	Trim Gas Oil	2007	2,268,000	16,800,000	biofilter
TK-SP-4	Trim Gas Oil	2007	2,268,000	16,800,000	biofilter
TK-LG-1	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-2	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-3	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-4	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-5	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-6	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-7	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-8	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-9	Asphalt	2007	4,746,000	50,400,000	biofilter
TK-LG-10	Trim Gas Oil	2007	2,268,000	16,800,000	biofilter
TK-LG-11	Trim Gas Oil	2007	2,268,000	16,800,000	biofilter
TK-LG-12	Asphalt with Polymer	2007	2,100	420,000	biofilter
TK-LG-13	Asphalt-Polymer Blend	2007	31,500	2,100,000	biofilter

Tank ID	Liquid Stored	Date Approved for Construction	Tank Storage Capacity (gallons)	Maximum Throughput (gallons/yr)	Exhaust ID
TK-LG-14	Polymer Finished Asphalt	2007	126,000	2,520,000	biofilter
TK-LG-15	Polymer Finished Asphalt	2007	126,000	2,520,000	biofilter
TK-LG-16	Polymer Finished Asphalt	2007	126,000	2,520,000	biofilter
TK-LG-17	Polymer Finished Asphalt	2007	126,000	2,520,000	biofilter

Under 40 CFR 60, Subpart UU, storage tanks TK-SP-1, TK-SP-2, TK-LG-1 through TK-LG-9, and TK-LG-12 through TK-LG-17 are each considered an affected facility.

Under 40 CFR 63, Subpart CC, storage tanks TK-3573, TK-SP-1 through TK-SP-4, TK-LG-1 through TK-LG-17 are each considered as Group 2 storage vessels that are part of the existing affected source.

(5) The following heated vertical storage tank, with a fixed cone roof, in heavy liquid service, storing volatile organic liquids that have a vapor pressure less than 0.0435 psia, and exhausting to the atmosphere:

Tank ID	Liquid Stored	Construction Date	Tank Storage Capacity (gallons)	Maximum Throughput (gallons/year)	Exhaust ID
TK-3570	Trim Gas Oil	1971	2,730,000	20,160,000	TK-3570

Under 40 CFR 63, Subpart CC, storage tank TK-3570 is considered as a Group 2 storage vessel that is part of the existing affected source.

(6) one (1) truck loading rack, approved for construction in 2007, comprised of six (6) loading bays used for loading liquid asphalt product, with a total maximum loading capacity of 800,000 tons of asphalt product per year, exhausting to the atmosphere or to a biofilter system for odor control.

(7) one (1) rail car loading rack, approved for construction in 2007, comprised of twenty-eight (28) loading bays used for loading liquid asphalt product, with a total maximum loading capacity of 800,000 tons of asphalt product per year, exhausting to the atmosphere or to a biofilter system for odor control.

(8) Equipment leaks of VOC and HAP from valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, flanges and/or other connectors.

Under 40 CFR 60, Subpart GGG, valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, flanges and/or other connectors in VOC service, are considered part of the existing affected source.

(gg) One (1) pipeline (Cogen Steam Transfer Line) connecting BP's boilers (identified as emission units 501 and 503) with Whiting Clean Energy's heat recovery steam operator. The pipeline is used to exchange steam between the two facilities. The pipeline was constructed in 2001.

(hh) One (1) pipeline (US Steel Stream Transfer Line) connecting BP's steam header with US Steel East Chicago (Plant ID #089-00300). This pipeline was constructed 2005 through 2006 and is used to transfer steam from BP to US Steel.

(ii) One (1) Marine Dock Facility used to store and transfer products. The facility has three dock berths. A process heater is used to keep certain tanks at the proper temperature for shipping. **As part of the CXHO Project, a vapor recovery/control system will be installed on the Marine Dock Loading operations to control emissions from gasoline loading**. This facility includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) One (1) natural gas-fired process heater (identified as Marine Dock Heater F-100), having a maximum heat input capacity of 7 MMBtu per hour.

(2) One (1) storage tank (identified as BT-1), constructed in 1990, with a maximum storage capacity of 706,000 gallons and used to store petroleum hydrocarbons with a vapor pressure less than 15 psia. The tank is equipped with a fixed roof and an internal floating roof.

(3) One storage tank (BT-002), constructed in 1968, permitted for modification in 2008, with a maximum storage capacity of 874,944 gallons, used to store petroleum hydrocarbons with a vapor pressure less than 15 psia, with a fixed roof and an internal floating roof.

(jj) The refinery operates ~~eight~~ **eleven** hydrocarbon flares. The flares are used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

The flares are identified as follows:

Flare	Stack ID	Date of Installation	Dimensions	Process Units Normally Controlled by the Flare System *	Maximum Capacity (MMBtu/hr)	Pilot Fuel Type
4UF Flare	224-06	1972	H = 200 ft, D = 2.5 ft.	ARU, CFU, BOU, 4UF	15,000	Fuel Gas and Natural Gas
FCU flare	230-02	1945	H = 200 ft. D = 2.0 ft.	FCU 600	5620	Fuel Gas and Natural Gas
UIU Flare	220-04	1958	H = 199.5 ft. D = 2.5 ft.	ISOM, 3UF, 2TP, CRU	7550	Fuel Gas and Natural Gas
VRU Flare	241-01	Unknown	H = 200 ft. D = 2.0 ft.	VRU 100,VRU200, VRU 300, FCU 500	1596	Fuel Gas and Natural Gas
Alky Flare	140-01	1961	H = 199.5 ft D = 2.5 ft.	PCU, Alky	3920	Fuel Gas and Natural Gas
SRU Flare	162-03	1971	H = 300 ft. D = 1.5 ft.	SRU	688	Fuel Gas and Natural Gas
DDU Flare	698-02	1993	H = 200 ft. D = 1.5 ft.	DDU, HU, Coker, DHT	6000	Fuel Gas and Natural Gas
LPG Flare	604-01	1986	H = 50 ft. D = 1.2 ft.	LPG storage vessels and loading facilities	30	LPG

Flare	Stack ID	Date of Installation	Dimensions	Process Units Normally Controlled by the Flare System *	Maximum Capacity (MMBtu/hr)	Pilot Fuel Type
PIB Flare**	2	1982	H = 250 ft. D = 3.0 ft.	RGP/PGP Loading Rack	540,000 lb/hr	Fuel Gas and Natural Gas
GOHT Flare* **	**802-03**	**Installed as Part of CXHO**	**H = 316 ft. D = 3.5 ft**	**GOHT**	**TBD**	**Fuel Gas and Natural Gas**
South Flare* **	**800-04**	**Installed as Part of CXHO**	**H = 350 ft. D = 5 ft**	**New Coker (#2 Coker), 12PS, Sulfur Recovery Complex**	**TBD**	**Fuel Gas and Natural Gas**

* - During emergencies or flare outages, some emission units or streams may be controlled by an alternate flare system that complies with the same applicable requirements as the flare normally used to control the emissions for those units.
** - Owned and operated by INEOS USA, LLC. (Plant I.D. 089-00076).
***** - Flares are equipped with a flare gas recovery system. The recovered gas streams will be sent to vapor recovery/treating area for removal of H_2S and heavy components before being utilized in the refinery fuel gas system.**

(kk) The OSBL area includes the pipe alleys, laboratory dock and waste transfer pad. The pipe alleys contain pipes that transfer hydrocarbon streams from one process unit to another or to storage. This facility includes leaks from process equipment, including open-ended valves or lines and flanges. This facility also contains area drains and an oil/water separator. This facility may ~~also~~ include insignificant activities listed in section A.4 of this permit.

(ll) The Distillate Hydrotreating (DHT) Unit, identified as Unit ID 720 and rated at 45,000 barrels per day, which removes sulfur from petroleum distillates. Distillate feed is mixed with hydrogen, heated in a process furnace and passed over a catalyst bed to convert sulfur compounds to H_2S. The DHT Unit was constructed in 2005/2006 and includes the following emission units:

(1) DHT Unit Heater B-601, rated at 20 MMBtu per hour and constructed in May 2005. **As part of the CXHO Project, DHT Unit Heater B-601 will be replaced with a 41.9 MMBtu per hour natural gas fired heater, identified as B-601A.** NO_X emissions are controlled by ultra low-NO_X burners having an emission rate of 0.04 pounds per million Btu heat input or less. Emissions are exhausted to a stack identified as 720-01.

(2) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

The DHT Unit shares the DDU Flare, used to control VOC emissions during emergency situations, unit startups and shutdowns.

(mm) The Gas Oil Hydrotreater (GOHT) Unit, identified as Unit ID 802 and rated at 120,000 barrels per day. The GOHT reduces the sulfur and nitrogen content of the FCU feed and improves the hydrogen content. Operation of the GOHT will enable the FCU to meet gasoline sulfur specifications and to improve FCU conversion yields. The GOHT Unit will be constructed as part of the CXHO Project and includes the following emission units:

(1) Process heaters comprising of:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-901A	**47**	**802-01**	**Ultra low-NO_X burners**
F-901B	**47**	**802-02**	**Ultra low-NO_X burners**

(2) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(2) The GOHT Unit vents to the GOHT Flare, used to control VOC emissions during emergency situations, unit startups and shutdowns.

(nn) The New Hydrogen (New HU), identified as Unit ID 801 constructed as part of the CXHO Project, produces 99+% pure hydrogen needed for the refinery hydrotreating processes. The New HU produces high purity hydrogen by reacting steam with methane. The New HU heaters HU-1 and HU-2 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New HU heater stacks have continuous emissions monitors (CEMs) for NOx and CO. The New HU includes the following sources of emissions and may include insignificant activities listed in Section A.4 of this permit:

(1) Process heaters comprising:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted to	Emission Controls
HU-1	920*	801-01	Low-NO_X burners and selective catalytic reduction
HU-2	920*	801-02	Low-NO_X burners and selective catalytic reduction

*** HU Heaters HU-1 and HU-2 combust both natural gas and PSA tail gas with a fuel ratio of no more than 25% natural gas and the remainder PSA tail gas.**

(2) One cooling tower (HU Cooling Tower) rated at 2,000 gallons per minute recirculation rate controlled by high efficiency drift eliminators.

(3) The new Hydrogen Unit is connected to the HU Flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The HU Flare will be operated with a water seat or nitrogen purge. As such, there will be no purge gas emissions from the HU Flare. The HU Flare exhausts to S/V 801-03.

(3) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(oo) Two (2) new boilers, identified as New Boiler 1 and New Boiler 2, permitted in 2008, each rated at 580 million BTU per hour, equipped with low-NOx burners and/or Selective Catalytic Reduction (SCR) for control of NOx, using either blended natural gas and refinery gas or only refinery fuel gas. A separate TRS CEMS shall be installed to measure the sulfur content of the fuel gas or fuel gas-natural gas blend fed to New Boiler 1 and New Boiler 2.

A.4 Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)]

This stationary source also includes the following insignificant activities, as defined in 326 IAC 2-7-1(21):

(a) Paved and unpaved roads and parking lots with public access, including road sweeping [326 IAC 6.8-10-3] [326 IAC 2-7-1(21)(G)(xiii)];

(b) Asbestos abatement projects regulated by 326 IAC 14-10 [326 IAC 2-7-1(21)(G)(xvi)];

(c) The following equipment related to manufacturing activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment [326 IAC 6.8-1-2(a)] [326 IAC 2-7-1(21)(G)(vi)(EE)];

(d) Machining where an aqueous cutting coolant continuously floods the machining interface [326 IAC 6.8-1-2(a)] [326 IAC 2-7-1(21)(G)(vi)(BB)];

(e) Stockpiled soils from soil remediation activities that are covered and waiting transport for disposal [326 IAC 6.8-10-3] [326 IAC 2-7-1(21)(G)(xii)];

(f) Emission units with PM and PM_{10} emissions less than five (5) tons per year, SO_2, NO_x, and VOC emissions less than ten (10) tons per year, CO emissions less than twenty-five (25) tons per year, lead emissions less than two-tenths (0.2) tons per year, single HAP emissions less than one (1) ton per year, and combination of HAPs emissions less than two and a half (2.5) tons per year [326 IAC 2-1.1-3(e)(1) and 326 IAC 2-7-1(21)(A)-(C)]:

(1) FCU catalyst handling including truck loading/unloading [326 IAC 6.8-1-2(a)];

(2) Power Station soot blows [326 IAC 6.8-1-2(a)];

(3) General excavations for site remediation activities [326 IAC 6.8-10-3];

(4) Fugitive dust from coke yard, sulfur piles, and sulfur pits [326 IAC 6.8-10-3]; and

(5) Soil Screening [326 IAC 6.8-10-3].

(g) Emissions from a laboratory, as defined in 326 IAC 2-7-1(21)(D).

(h) Combustion activities related to the following [326 IAC 2-7-1(21)(G)(i)]:

(1) Space heaters, process heaters, heat treat furnaces, or boilers using the following fuels:

(i) Natural gas, provided the heat input of the unit is equal to or less than 10 MMBtu/hr.

(ii) The following five (5) natural gas-fired hot oil heaters, each approved for construction in 2007, and each considered an insignificant activity, as defined in 326 IAC 2-7-1(21)(G)(i)(AA)(aa):

Process Heater ID	Heat Input Capacity (MMBtu/hr)	Fuel	Control Device
H-SP-1	9.9	Natural gas	none
H-SP-2	9.9	Natural gas	none
H-LG-1	9.9	Natural gas	none
H-LG-2	9.9	Natural gas	none
H-LG-3*	9.9	Natural gas	none

*Hot oil heater H-LG-3 will exhaust to a steam generator that will be used to heat rejected loads of asphalt during unloading.

(iii) Propane, liquified petroleum gas, or butane, provided the heat input of the unit is equal to or less than 6 MMBtu/hr.

(iv) Fuel oil, provided the heat input of the unit is equal to or less than 2 MMBtu/hr and the fuel contains equal to or less than 0.5% sulfur by weight.

(2) Equipment powered by diesel fuel fired or natural gas fired internal combustion engines of capacity equip to or less than 500,000 Btu per hour.

(3) Combustion source flame safety purging on startup.

(i) One (1) fuel dispensing operation, constructed in 2005, dispensing less than or equal to 1,300 gal/day into motor vehicle fuel tanks and with emissions less than the insignificant activity emission thresholds in 326 IAC 2-7-1(21)(A) through (C). The dispensing facility consists of a vapor balance system to control emissions and the following two (2) storage tanks [326 IAC 8-4-6]:

(A) One (1) gasoline storage tank, constructed in 2005, having a maximum storage capacity of 12,000 gallons.

(B) One (1) diesel storage tank, constructed in 2005, having a maximum storage capacity of 6,000 gallons.

(j) The following VOC and HAP storage containers [326 IAC 2-7-1(21)(G)(iii)]:

(1) Storage tanks with capacity less than or equal to one thousand (1,000) gallons and annual throughputs equal to or less than twelve thousand (12,000) gallons.

(2) Vessels storing lubricating oils, hydraulic oils, machining oils, or machining fluids.

(k) Production related activities, including the application of oils, greases, lubricants, and non-volatile material such as temporary protective coatings [326 IAC 2-7-1(21)(G)(vi)(AA)].

(l) Degreasing operations that do not exceed 145 gallons per twelve (12) months, except if subject to 326 IAC 20-6 [326 IAC 2-7-1(21)(G)(vi)(CC)] [326 IAC 8-3-2] [326 IAC 8-3-5].

(m) Cleaners and solvents with a vapor pressure equal to or less than 0.3 psia at 100°F or 0.1 psia at 68°F and for which the combined use for all materials does not exceed 145 gallons per 12 months [326 IAC 2-7-1(21)(G)(vi)(DD)].

(n) Closed loop heating and cooling systems [326 IAC 2-7-1(21)(G)(vi)(FF)].

(o) Ground water oil recovery wells [326 IAC 2-7-1(21)(G)(vii)(BB)].

(p) Activities associated with the treatment of wastewater streams with an oil and grease content less than or equal to 1% by volume [326 IAC 2-7-1(21)(G)(ix)(AA)].

(q) Water run-off ponds for petroleum coke-cutting and coke storage piles [326 IAC 2-7-1(21)(G)(viii)(BB)].

(r) Any operation using aqueous solvents containing less than or equal to 1% by weight of VOCs excluding HAPs [326 IAC 2-7-1(21)(G)(viii)(DD)].

(s) Non-contact cooling tower systems with either natural draft or forced and induced draft systems not regulated under a NESHAP [326 IAC 2-7-1(21)(G)(viii)(FF)].

(t) Activities associates with the transportation and treatment of sanitary sewage, provided discharge to the treatment plant is under the control of the owner or operator, that is, an on-site sewage treatment facility [326 IAC 2-7-1(21)(G)(viii)(CC)].

(u) Repair activities including the following [326 IAC 2-7-1(21)(G)(x)]:

(1) Replacement or repair of ESPs, bags in baghouses, and filters in other air filtration equipment.

(2) Heat exchanger cleaning and repair.

(3) Process vessel degassing and cleaning to prepare for internal repairs.

(v) Coke conveying operations, as provided in 326 IAC 2-7-1(21)(G)(xiv).

(w) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including catch tanks, temporary liquid separators, tanks, and fluid handling equipment [326 IAC 2-7-1(21)(G)(xix)].

(x) Blowdown for sight glasses, boilers, cooling towers, compressors, or pumps [326 IAC 2-7-1(21)(G)(xx)].

(y) Emergency generators meeting one of the following criteria [326 IAC 2-7-1(21)(G)(xxii)(BB)]:

(1) Gasoline generators not exceeding 110 horsepower.

(2) Diesel generators not exceeding 1,600 horsepower.

(3) Natural gas turbines or reciprocating engines not exceeding 16,000 horsepower.

(z) Other activities associated with emergencies, including on-site fire training approved by the department and stationary fire pump engines [326 IAC 2-7-1(21)(G)(xxii)]

(aa) A warehouse identified as the Calumet Warehouse that includes the following emission sources and may ~~also~~ include other insignificant activities listed in Section A.4 of this permit [326 IAC 6.8-1-2(b)]:

(1) Kewanee Boiler No. 1 with a maximum design capacity of 5.5 MMBtu/hr heat input and is natural gas-fired only, venting to stack, S-1.

(2) Kewanee Boiler No. 2 with a maximum design capacity of 5.5 MMBtu/hr heat input and is natural gas-fired only, venting to stack, S-2.

(bb) Routine maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process, including the following [326 IAC 2-7-1(21)(G)(xvii)]:

(1) Purging of gas lines.

(2) Purging of vessels.

(cc) Flue gas conditioning systems and associated chemicals, such as the following [326 IAC 2-7-1(21)(G)(xviii)]:

(1) Sodium sulfate.

(2) Ammonia.

(3) Sulfur trioxide.

(dd) Purge double block and bleed valves [326 IAC 2-7-1(21)(G)(xxiv)].

(ee) Filter or coalescer media changeout [326 IAC 2-7-1(21)(G)(xxv)].

(ff) Three (3) emergency firepump engines, identified as Firepump 1, 2 and 3, permitted in 2008, each rated at 390 HP.

(gg) One (1) concrete crushing process, permitted in 2008, with a maximum processing capacity of 120 tons per hour, having two (2) transfer points.

A.5 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

SECTION D.0 FACILITY OPERATION CONDITIONS - CXHO Project

Facility Description [326 IAC 2-7-5(15)]

Emissions units - new, modified and affected by CXHO project, including the following:

<u>New Process Heaters</u>
DHT B-601A
GOHT F-901A and F-901B
12 PS H-101A, H-101B and H-102
New Coker (#2 Coker) H-201, H-202, and H-203
New Hydrogen Unit HU-1 and HU-2

<u>Modified Process Heaters</u>
11C PS H-200
BOU F-401
ISOM H-1

<u>Affected Process Heaters</u>
11A PS H-1X, H-2, H-3
11C PS H-300
4UF F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, F-8B
ARU F-200A, F-200B
CFHU F-801A, F-801B, F-801C
CRU F-101, F-102
DDU WB-301, WB-302
HU B-501

<u>Cooling Towers</u>
Existing (affected) Cooling Towers 2, 3, 4
New Cooling Tower 7
New Cooling Tower 8
New HU Cooling Tower

<u>SRU</u>
New Claus Offgas Treaters (COTs) 1 and 2

<u>New Flares</u>
GOHT Flare
South Flare
HU Flare

<u>Fugitive emission components from new units</u>
DHT
GOHT
12 PS
#2 Coker
SRU
OSBL
HU

<u>New Storage Tanks</u>
TK-6255
TK-SH-1 and TK-SH-2
TK-5052

Brine Treatment System

TK-105A (Off spec tank 1)
TK-105B (Off spec tank 2)
TK-101 (Separation tank 1)
TK-102 (Separation tank 2)
TK-103 (Separation tank 3)
TK-104A (Sludge holding tank 1)
TK-104B (Sludge holding tank 2)

Fluidized Catalytic Cracking Units
FCU 500
FCU 600

Other Miscellaneous Units
Marine Dock
VRU 400
Fugitive dust from new Coker (#2 Coker) coke handling
Pumps in Heavy Liquid Service
Leaks from process equipment, including compressors, pumps, valves, process drains and pressure relief devices.

Unrelated Emissions units - new, modified and affected future contemporaneous to CXHO project:

New Storage Tanks
TK-3637
BT-002
Tank 8a

New Boiler 1 and New Boiler 2
Five (5) duct burners at 3 SPS
Dewatering and thermal desorption process
Three (3) emergency firepumps
11A WARP
11C WARP
FCU 500 WARP
FCU 600 WARP
FCU 600 TAR
VRU 100/200 WARP

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.0.1 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

(a) Following the issuance of SPM 089-25488-00453 and until the startup of New Coker (#2 Coker) and associated coke handling facilities, the Permittee shall determine, on a monthly basis, the increase in emissions of SO2, NOx, PM, PM-10, CO and VOC from all new, modified and existing affected emission units at this source, and shall demonstrate, that the net emissions increases from this source remain below significant levels per twelve (12) consecutive month period beginning with issuance of SPM No. 089-25488-00453, in accordance with the following:

Following the issuance of SPM No. 089-25488-00453, and until the startup of the New Coker (#2 Coker) and associated coke handling facilities, the net emissions increases or decreases from the CXHO project, including fugitive emissions, shall be determined each month as follows:

Etotal = Emissions increases from new, modified, and affected emissions units during the past 12 month period
+ emissions increases from non-CXHO related projects during the past 12 month period
- creditable emissions decreases from CXHO related changes and creditable emissions decreases from non-CXHO related projects during the past 12 month period
+ emissions from creditable past contemporaneous increases
– emissions from creditable past contemporaneous decreases.

(b) Emissions from Boilers and Process Heaters shall be calculated as follows:

(1) For new heaters to be installed as part of the CXHO project, including replacement heaters, for pollutants that do not have a CEMS, the monthly emissions shall be calculated as follows:

$$Emissions\left(\frac{ton}{mo}\right) = (EF) * HI * \frac{1\,ton}{2{,}000\,lb}$$

Where:

HI	**=**	**Total actual heat input into unit i, in mmBtu, for the month**
EF	**=**	**Emission factor (lb/mmBTU) for heater as represented in Table D.0.1 or a more representative emission factors as verified through source testing per Condition D.0.3.**

(2) Emissions increases each month from the existing modified and affected process heaters and boilers not equipped with a CEMS shall be calculated as follows based on the emission factors in Table D.0.1 or a more representative emission factors as verified through source testing per Condition D.0.3:
E = (Actual Heat Input - Baseline Heat Input) (mmBTU) x Emission Factor (lb/mmBTU)

$$Emissions\left(\frac{ton}{mo}\right) = \left((HI_A * EF_A) - (HI_B * EF_B)\right) * \frac{1\,ton}{2{,}000\,lb}$$

Where,

HI_A = Actual Heat Input (mmBtu/mo)
HI_B = Baseline heat input (mmBTU/mo)

EF_A = Actual emission factor (lb/mmBTU)
EF_B = Baseline emission factor (lb/mmBTU).

Table D.0.1 Emission Factors in lb/mmBTU					
Process Unit	**VOC**	**NOx**	**CO**	**PM**	**PM10/PM2.5**
11A PS					
H-1X	**0.0054**	**0.166**	**0.082**	**0.0019**	**0.0075**
H-2	**0.0054**	**0.098**	**0.082**	**0.0019**	**0.0075**
H-3	**0.0054**	**0.098**	**0.082**	**0.0019**	**0.0075**
11C PS					
H-200	**0.0054**	**0.275***	**0.082**	**0.0019**	**0.0075**
H-300	**0.0054**	**0.137**	**0.082**	**0.0019**	**0.0075**
New #2 Coker					
H-201	**0.0054**	**0.02**	**0.019**	**0.0019**	**0.0081*** **

Table D.0.1 Emission Factors in lb/mmBTU					
Process Unit	**VOC**	**NOx**	**CO**	**PM**	**PM10/PM2.5**
H-202	**0.0054**	**0.02**	**0.019**	**0.0019**	**0.0081*** **
H-203	**0.0054**	**0.02**	**0.019**	**0.0019**	**0.0081*** **
12 PS					
H-101A	**0.0054**	**0.05**	**0.019**	**0.0019**	**0.0075**
H-102	**0.0054**	**0.05**	**0.019**	**0.0019**	**0.0075**
H-101B	**0.0054**	**0.05**	**0.019**	**0.0019**	**0.0075**
4UF					
F-1	**0.0054**	**0.098**	**0.082**	**0.0019**	**0.0075**
F-8A	**0.0054**	**0.275**	**0.082**	**0.0019**	**0.0075**
F-8B	**0.0054**	**0.275**	**0.082**	**0.0019**	**0.0075**
F-2	**0.0054**	**0.186**	**0.082**	**0.0019**	**0.0075**
F-3	**0.0054**	**0.275**	**0.082**	**0.0019**	**0.0075**
F-4	**0.0054**	**0.275**	**0.082**	**0.0019**	**0.0075**
F-5	**0.0054**	**0.098**	**0.082**	**0.0019**	**0.0075**
F-6	**0.0054**	**0.098**	**0.082**	**0.0019**	**0.0075**
F-7	**0.0054**	**0.098**	**0.082**	**0.0019**	**0.0075**
ARU					
F-200A	**0.0054**	**0.275**	**0.082**	**0.0019**	**0.0075**
F-200B	**0.0054**	**0.275**	**0.082**	**0.0019**	**0.0075**
BOU					
F-401	**0.0054**	**0.098**	**0.082**	**0.0019**	**0.0075**
CFHU					
F-801A	**0.0054**	**0.049**	**0.082**	**0.0019**	**0.0075**
F-801B	**0.0054**	**0.049**	**0.082**	**0.0019**	**0.0075**
F-801C	**0.0054**	**0.036**	**0.0001**	**0.0019**	**0.0075**
GOHT					
F-901A	**0.0054**	**0.04**	**0.02**	**0.0019**	**0.0075**
F-901B	**0.0054**	**0.04**	**0.02**	**0.0019**	**0.0075**
CRU					
F-101	**0.0054**	**0.080**	**0.082**	**0.0019**	**0.0075**
F-102	**0.0054**	**0.080**	**0.082**	**0.0019**	**0.0075**
DDU					
WB-301	**0.0054**	**0.035**	**0.04**	**0.0019**	**0.0075**
WB-302	**0.0054**	**0.030**	**0.04**	**0.0019**	**0.0075**
DHT					
B-601/B-601A	**0.0054**	**0.040**	**0.04**	**0.0019**	**0.0075**
ISOM					
H-1	**0.0054**	**0.275**	**0.082**	**0.0019**	**0.0075**
HU					
B-501	**0.0054**	**0.068**	**0.02**	**0.0019**	**0.0075**
New HU (3rd Party SMR)					
HU-1	**0.0034**	**0.013**	**0.015**	**0.0068**	**0.0068*** **
HU-2	**0.0034**	**0.013**	**0.015**	**0.0068**	**0.0068*** **
3 SPS Boilers 1, 2, 3, 4, 6 Duct Burners	**0.0054**	**0.02**	****	**0.0019**	**0.0087*** **

Table D.0.1 Emission Factors in lb/mmBTU					
Process Unit	**VOC**	**NOx**	**CO**	**PM**	**PM10/PM2.5**
for SCRs					

*** This factor will be 0.05 lb/mmBTU following installation of low NOx burners.**
**** CO emissions will be measured using a CO analyzer.**
***** Includes PM_{10}/PM2.5 generated from SCR**

(3) Emissions increases of SO_2 shall be calculated as follows:

$$SO_2\ Emissions\left(\frac{ton}{mo}\right)=\left(D_A * SO_2\ EF_A * \frac{1}{HHV_A} - D_B * SO_2\ EF_B * \frac{1}{HHV_B}\right) * \frac{1\,ton}{2{,}000\,lb}$$

Where,

D_A = Actual Heat Input (mmBtu/mo)
D_B = Baseline heat input (mmBTU/mo)
HHV_A = Actual Fuel gas higher heating value (mmBtu/mmcf)
HHV_B = Baseline Fuel gas higher heating value (mmBtu/mmcf)
SO_2 EF_A = Actual SO_2 emission factor (lb/mmcf)
SO_2 EF_B = Baseline SO_2 emission factor (lb/mmcf).

The SO_2 emission factor is a function of the total sulfur concentration in the fuel gas and is calculated from the Ideal Gas Law as follows:

$$SO_2\ EF = \frac{C * MW * P}{R * T}$$

Where,

C = Fuel gas total sulfur concentration (ppm)
MW = Molecular Weight (lb/lbmol)
P = Pressure (psia)
R = Ideal Gas Constant (psia*ft3/(lbmol*R))
T = Temperature (R)

Until total sulfur monitors are installed on the fuel gas system, total sulfur in the fuel gas shall be determined as follows:
Total sulfur (ppm) = H_2S (ppm) + Mercaptan (ppm)
Where,
H_2S (ppm) = concentration of H_2S in fuel gas as measured by existing fuel continuous H_2S analyzers.
Mercaptan (ppm) = 111 ppm (or a revised average concentration based on sampled data)

(c) Emissions increases from FCU 500 and FCU 600 shall be calculated as follows:

(A) SO_2, NO_x, and CO emissions increases or decreases (actual emissions for that month - baseline emissions) shall be calculated from CEMS data collected at the FCU 500 and FCU 600 exhaust stacks using the following formulas:

$$\text{Emissions}\left(\frac{\text{ton}}{\text{mo}}\right)=\left[C_A * \text{coke}_A * \left(11.6\frac{\text{lb Exhaust Gas}}{\text{lb coke}}\right)\left(\frac{\text{MW Pollutant}}{\text{MW Exhaust Gas}}\right)*\frac{1\text{ ton}}{2{,}000\text{ lb}}\right]-$$

$$\left[C_B * \text{coke}_B * \left(11.6\frac{\text{lb Exhaust Gas}}{\text{lb coke}}\right)\left(\frac{\text{MW Pollutant}}{\text{MW Exhaust Gas}}\right)*\frac{1\text{ ton}}{2{,}000\text{ lb}}\right]$$

Where,

C_A = Actual Pollutant concentration (ppm) at 0% excess oxygen

$Coke_A$ = Actual Total coke burned (lb/mo)

C_B = Baseline Pollutant concentration (ppm) at 0% excess oxygen

$Coke_B$ = Baseline Total coke burned (lb/mo)

Ratio of Exhaust Gas (lb):coke (lb) = 11.6 per refinery engineering estimates

(B) VOC and $PM/PM_{10}/PM_{2.5}$ emissions increases or decreases (actual emissions - baseline emissions) shall be calculated based on the increase in the amount of feed to the unit and the calculated coke burn rate combined with the following emission factors:

$$\text{VOC Emissions}\left(\frac{\text{ton}}{\text{mo}}\right)=\left[EF_A * \text{Feed}_A * \frac{1\text{ ton}}{2{,}000\text{ lb}}\right]-\left[EF_B * \text{Feed}_B * \frac{1\text{ ton}}{2{,}000\text{ lb}}\right]$$

Where for FCU 500 and FCU 600:
EF_A = 3.3 lb VOC/1000 barrels of feed
$Feed_A$ = Actual Feed (1000 barrels feed/month)
EF_B = 3.3 lb VOC/1000 barrels of feed
$Feed_B$ = Baseline Feed (1000 barrels feed/month)

$$\text{PM/PM10/PM2.5 Emissions}\left(\frac{\text{ton}}{\text{mo}}\right)=\left[EF_A * \text{coke}_A * \frac{1\text{ ton}}{2{,}000\text{ lb}}\right]-\left[EF_B * \text{coke}_B * \frac{1\text{ ton}}{2{,}000\text{ lb}}\right]$$

Where for FCU 500:
EF_A = 0.465 lb $PM/PM_{10}/PM_{2.5}$ per 1000 lb coke burned
$Coke_A$ = Actual coke burn rate (1000 lb/month)
EF_B = 0.465 lb $PM/PM_{10}/PM_{2.5}$ per 1000 lb coke burned
$Coke_B$ = Baseline coke burn rate (1000 lb/month)

Where for FCU 600:
EF_A = 0.35 lb $PM/PM_{10}/PM_{2.5}$ per 1000 lb coke burned
$Coke_A$ = Actual coke burn rate (1000 lb/month)
EF_B = 0.35 lb $PM/PM_{10}/PM_{2.5}$ per 1000 lb coke burned
$Coke_B$ = Baseline coke burn rate (1000 lb/month)

(d) The Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM, OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

Fugitive VOC emissions from valves, pumps, and flanges shall be determined as follows:

VOC Emissions (tpy) =

$$N * (CE_{comp}) * [(EF_{leak} * Leak) + EF_{no\text{-}leak} * (1- Leak)] * VOC_{comp}$$

Where:

N = No. of components added or removed (valve/pump/flange/drain/relief device)
VOC_{comp} = Percent VOC service for component
Leak = Fraction of components experiencing leaks
CE_{comp}= LDAR Control efficiency for the type of component (valve/pump/flange/drain/relief device)
EF_{leak} = EPA's refinery screening emission factor (leak) for type of component
$EF_{no\text{-}leak}$ = EPA's refinery screening emission factor (no leak) for type of component

For purposes of this calculation, new components are considered " added" on the date that a new or modified process unit starts up,

The decreases in fugitive VOC emissions from valves, pumps, flanges, drains and pressure relief devices, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for VOC for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

(e) For all emissions units involved in heavy liquid service, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service. The Permittee shall update the LDAR Plan to indicate that the methodologies in 40 CFR 60.482 shall apply to all pumps in heavy liquid service and shall submit a copy of the revised LDAR Plan to IDEM, OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

VOC emissions decreases from existing pumps in heavy liquid service shall be determined as follows:

$$\text{Emissions decrease (tpy)} = N * (CE_{project} - CE_{current}) * [(EF_{leak} * Leak) + EF_{no\text{-}leak} * (1\text{-}Leak)] * VOC_{comp}$$

Where:

N = No. of existing heavy liquid pumps
VOC_{comp} = Fraction of heavy liquid components in VOC service
$CE_{project}$ = Proposed control efficiency due to enhanced LDAR monitoring

$CE_{current}$ = Current control efficiency
EF_{leak} = EPA's refinery screening emission factor (leak)
$EF_{no\text{-}leak}$ = EPA's refinery screening emission factor (no leak)
Leak = Fraction of components experiencing leaks

(f) PM and PM-10 Emissions decreases from existing cooling towers (due to installation of any liquid drift eliminator) shall be calculated based on the following:

Emissions decrease = Baseline Emissions - Actual Emissions

Actual PM/PM-10 emissions =
(Recirculation Rate + Make-up Rate) (gal/min) x AP42 Ef (0.019 lb/1,000 gal)
$(TLD_{design}/TLD_{AP\text{-}42}) \times (TDS_{allowable}/TDS_{AP\text{-}42})$

Where:

TLD = Total liquid drift, percentage
TDS = Total dissolved solids, mg/L

Compliance Determination Requirements

D.0.2 Operating Requirements

(a) After the installation of the continuous BTU analyzers at fuel mixing drums, in order to demonstrate compliance with emissions limitations, the continuous BTU analyzer shall be calibrated, maintained, and operated for determining compliance with the firing rate limits for heaters and boilers that are new, modified or affected units related to the CXHO project.

(b) Prior to the installation of the continuous BTU analyzers, in order to demonstrate compliance with the firing rate limits on heaters and boilers involved in the CXHO project, the Permittee shall:

(1) Continuously monitor the fuel flow rates at the heaters and boilers;

(2) Conduct a monthly analysis of fuel gas samples taken once per week in order to determine monthly averaged BTU content of the fuel gas in each mixing drum; and

(3) Determine the monthly firing rates for heaters and boilers based on the fuel flow rates at each heater and boiler and the monthly averaged BTU content of the fuel gas in the mixing drums.

D.0.3 Testing Requirements

(a) Tests shall be conducted on new, modified and affected emission units that are included in the CXHO project, utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C - Performance Testing. PM-10 includes both filterable and condensible PM-10. These tests shall be repeated at least once every five years from the date of the previous valid compliance demonstration.

(b) Tests shall be conducted in accordance with the following deadlines:

(1) For a group that includes new or modified emission units (CO-1, PM/VOC-1, PM/VOC-2, PM/VOC-3, PM/VOC-4, VOC-6, PM/VOC-7, NOx-1, NOx-4, NOx-8, NOx-12), tests shall be conducted on one of the representative heaters in that group: within 180 days of the installation of a new emission unit, or modification of an existing emission unit within that group.

(2) For a group that includes only existing affected units (CO-2, CO-3, CO-4, PM/VOC-5, PM/VOC-8, PM/VOC-9, NOx-2, NOx-3, NOx-5, NOx-6, NOx-7, NOx-9, NOx-10, NOx-11), tests shall be conducted on one of the representative heaters in that group:: within 180 days of the startup of New Coker (#2 Coker).

(c) The emissions units to be tested in order to demonstrate compliance with Prevention of Significant Deterioration (326 IAC 2-2), Emission Offset (326 IAC 2-3) and Nonattainment NSR (326 IAC 2-1.1-5) minor limits shall be grouped as follows:

Table D.0.2 Test Groups

Pollutant	Test Group ID	Emission Units in Group
CO	CO-1	11A PS heaters H-1X, H-2, H-3 11C PS heaters H-200, H-300 4 UF heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, F-8B ARU heaters F-200A, F-200B BOU heater F-401 CFHU heaters F-801A, F-801B CRU heaters F-101, F-102 ISOM heater H-1
	CO-2	DDU heaters WB-301, WB-302
	CO-3	HU heater B-501
	CO-4	CFHU heater F-801C
	No stack test required (equipped with CO CEMS)	New Coker (#2 Coker) heaters H-201, H-202, H-203 12 PS heaters H-101A, H-101B, H-102 DHT heater B-601A New HU heaters HU-1, HU-2 SRU COT1, COT2 FCU 500, FCU 600 3 SPS boilers/duct burners 1, 2, 3, 4, 6 New Boiler 1, New Boiler 2
VOC and PM/PM-10 * VOC test group only	PM/VOC-1	New Coker (#2 Coker) heaters H-201, H-202, H-203
	PM/VOC-2	New HU heaters HU-1, HU-2
	PM/VOC-3	SRU COT1, COT2
	PM/VOC-4	11C PS heater H-200 12 PS heaters H-101A, H-101B, H-102 BOU heater F-401 GOHT heaters F-901A, F-901B DHT heater B-601A ISOM heater H-1 HU heater B-501
	PM/VOC-5	11A PS heaters H-1X, H-2, H-3 11C PS heater H-300 4UF heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A,F-8B ARU heaters F-200A, F-200B CFHU heaters F-801A, F-801B, F-801C CRU heaters F-101, F-102 DDU heaters WB-301, WB-302
	VOC-6*	3 SPS boilers 1, 2, 3, 4, 6
	PM/VOC-7	New Boiler 1, New Boiler 2
	PM/VOC-8	FCU 500
	PM/VOC-9	FCU 600

Table D.0.2 Test Groups		
Pollutant	**Test Group ID**	**Emission Units in Group**
NOx	**NOx-1**	**CFHU heater F-801C GOHT heaters F-901A, F-901B DDU heater WB-301**
	NOx-2	**11C PS heater H-200**
	NOx-3	**CRU heaters F-101, F-102**
	NOx-4	**4UF heaters F-3, F-4, F-8A, F-8B ARU heaters F-200A, F-200B ISOM heater H-1**
	NOx-5	**4UF heater F-2**
	NOx-6	**11A PS heater H-1X**
	NOx-7	**11C PS heater H-300**
	NOx-8	**11A PS heater H-2, H-3 4UF heaters F-1, F-5, F-6, F-7 BOU heater F-401**
	NOx-9	**CFHU heaters F-801A, F-801B**
	NOx-10	**HU heater B-501**
	NOx-11	**DDU heater WB-302**
	NOx-12	**SRU COT1, COT2**
	No stack test needed (NOx CEMS)	**3 SPS boilers 1, 2, 3, 4, 6, New Boiler 1, New Boiler 2 New Coker (#2 Coker) heaters H-201, H-202, H-203 12 PS heaters H-101A, H-101B, H-102 New HU heaters HU-1, HU-2, and FCU 500, FCU 600 DHT heater B-601A**

(d) Within 180 days of the startup of New Coker (#2 Coker), in order to demonstrate compliance with the PM-10 emission factor limit from the SCR stacks at No. 3 Stanolind Power Station (3 SPS), testing shall be conducted on one (1) of the five (5) stacks for 3 SPS boiler/SCR stacks, utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C - Performance Testing. PM-10 includes filterable and condensible PM-10. This test shall be repeated at least once every five years from the date of the previous valid compliance demonstration.

(e) Compliance with the emissions limits for each emission unit or test group shall be determined as follows:

$$T = \left(\sum_{i=1}^{n} T_i\right) / n$$

Where:

T = average of IDEM approved stack test results for emission unit or all units within that same group over the previous 12 month period
T_i = average of multiple runs during Test #i
n = number of IDEM approved stack tests during previous 12 month period

Recordkeeping and Reporting Requirements

D.0.4 Recordkeeping Requirements

In order to demonstrate compliance with Condition D.0.1, the Permittee shall maintain the following records each month, upon issuance of the SPM No. 089-25488-00453 and until the startup of the New Coker (#2 Coker) and associated coke handling facilities:

(a) The emissions in tons, including fugitive emissions, of PM, PM-10, VOC, NOx, and SO2, from new emission units installed as part of the CXHO project during that month.

(b) The emissions increases and decreases from CXHO related projects, including modifications, shutdowns, and installation of controls, and emissions increases from existing affected units during the past 12 months.

(c) Emissions increases and decreases from non-CXHO related projects during the past 12 months.

(d) The net emissions increases or decreases as calculated each month in Condition D.0.1(a).

D.0.5 Reporting Requirements

(a) In order to demonstrate compliance with Condition D.0.1, no later than 45 days after the end of the first 12- calendar month period following the effective date of SPM No. 089-25488-00453, and every 6 months thereafter, the Permittee shall submit a report to IDEM documenting the net emissions increases or decreases for the CXHO project as calculated each month, as required in Condition D.0.1(e).

(b) The reporting requirements in Condition D.0.5(a) shall no longer be applicable following the startup of the New Coker (#2 Coker). Start-up is defined as when the unit becomes operational only after a reasonable shakedown period, not to exceed 180 days, pursuant to 326 IAC 2-2-1 (jj)(7).

SECTION D.1 FACILITY OPERATION CONDITIONS - No. 11 Pipe Still

Facility Description [326 IAC 2-7-5(15)]

(a) Nos. 11A and 11C Pipe Stills built in 1956, with a rated capacity of 220,800 barrels per day, and identified as Unit ID 120 process crude into various hydrocarbon fractions based on boiling points**.** This facility includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) The following process heaters, all of which are fired by natural gas, refinery gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-1X	250	120-01	None
H-2	45	120-02	None
H-3	55	120-03	None
H-200	249.5	120-05	**Current:** None **After CXHO: Low-NO_X Burners**
H-300	180	120-06	None

(2) Two (2) vacuum hot wells (D-21, constructed in 1990 and D-26, constructed in 1997) and one (1) sump (D-20, constructed in 1990), with D-20, D-21, and D-26 each venting to S/V 120-07, at No. 11 A Pipe Still.

(3) One (1) vacuum hot well (D-300), constructed in 1995 venting to S/V 120-08 at No. 11C Pipe Still.

The vacuum tower overhead system consists of a series of condensers, steam ejectors, and vacuum pumps. The majority of the overhead vapors are condensed and drained to the hotwell, which is pumped back to the front end of the unit for reprocessing. The gas compressors pull the remaining vapor that is not condensed in the overhead system into the wet gas system, where the hydrocarbon is reprocessed by down steam units. A thermocouple system (with temperature alarm) is used to monitor the vacuum on the system.

(4) Leaks from process equipment, including pumps; compressors (K4 and K4A at No. 11A Pipe Still and K300A and K300-B at the No. 11C Pipe Still); pressure relief devices; sampling connection systems; open-ended lines or valves; and instrumentation systems.

(5) One (1) storage tank (identified as Tank 3030) with a maximum storage capacity of 847,000 gallons. This tank was installed in 1957 and is equipped with an external floating roof.

(6) One (1) oil water separation system (identified as Tank 8), with a maximum storage capacity of 124,800 gallons.

(7) One (1) redundant oil water separation system (identified as Tank 8a), permitted in 2008, with a maximum storage capacity of 124,800 gallons, equipped with a carbon canister for VOC control.

(8) As part of the No. 11A PS and No. 11C PS WARP, permitted in 2008, the two existing blowdown stacks identified as stacks 11PS-A and 11PS-C will be shutdown, with the emergency pressure relief discharge that was previously routed to the blowdown stacks being re-routed to the DDU flare, except for T-300 vacuum tower relief discharge and the COV's.

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.1.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)), the Permittee shall comply with the following PM_{10} emission limitations for Nos. 11A and 11C Pipe Still process heaters:

Process Heater	PM_{10} Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
H-1X Heater	0.031	6.867
H2 Vacuum Heater	0.032	1.440
H3 Vacuum Heater	0.031	1.704
H-200 Crude Charge	0.032	7.866
H-300 Furnace	0.031	4.931

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.1.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) After the startup of the low-NOx burners on heater H-200, the emissions of NOx shall not exceed 0.05 pounds per million BTU of fuel gas fired.

(b) The Permittee shall comply with the following limits following the startup of the new Coker (#2 Coker):

(1) Annual firing rate and SO2 emissions limits:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO2 emissions (tons per 12 consecutive month period)
H-200	**1601.33**	**8.9**
H-300	**630.72**	**3.5**
H-1X	**1523.36**	**8.4**
H-2	**282.95**	**1.6**
H-3	**430.99**	**2.4**

(2) CO, VOC, NOx, PM and PM-10 emissions limits:

Heater ID	CO (lb/mmBTU)	VOC (lb/mmBTU)	NOx (lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
H-1X	**0.082**	**0.0054**	**0.166**	**0.0019**	**0.0075**
H-2	**0.082**	**0.0054**	**0.098**	**0.0019**	**0.0075**
H-3	**0.082**	**0.0054**	**0.098**	**0.0019**	**0.0075**
H-200	**0.082**	**0.0054**	**0.2745***	**0.0019**	**0.0075**

Heater ID	CO (lb/mmBTU)	VOC (lb/mmBTU)	NOx (lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
H-300	**0.082**	**0.0054**	**0.137**	**0.0019**	**0.0075**

*** 0.05 lb/mmBTU after startup of low-NOx burners**

(c) After the startup of the New Coker (#2 Coker), the two existing blowdown stacks identified as stacks 11PS-A and 11PS-C will be shutdown, with the emergency pressure relief discharge that was previously routed to the blowdown stacks being re-routed to the DDU flare, except for T-300 vacuum tower relief discharge and the COV's.

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.1.~~2~~**3** Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, the Permittee shall comply with the following sulfur dioxide emission limitations for the Nos. 11A and 11C Pipe Still process heaters:

Process Heater	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)
H-1X Heater	0.033	8.25
H-2 Vacuum Heater	0.033	1.49
H-3 Vacuum Heater	0.033	1.82
H-200 Crude Charge	0.033	8.23
H-300 Furnace	0.033	5.94

D.1.~~3~~**4** SO_2 Emission Limitations

Pursuant to Permit CP 089-3053-00003, issued on March 31, 1994, the Permittee shall comply with the following SO_2 emission limitations for Nos. 11A and 11C Pipe Still process heaters:

Process Heater	SO_2 Limit (lbs/MMBtu)
H-1X Heater	0.358
H-300 Furnace	0.357

D.1.~~4~~**5** Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for process heaters: H-1X Heater, H-2 Vacuum Heater, H-3 Vacuum Heater, H-200 Crude Charge, and H-300 Furnace.

D.1.~~5~~**6** Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems located at No. 11A Pipe Still.

D.1.~~6~~**7** Volatile Organic Compounds (VOC) [326 IAC 8-4-2]

(a) Pursuant to 326 IAC 8-4-2(1), the Permittee shall control VOC emissions from the vacuum producing systems at the No. 11A Pipe Still vacuum hot wells (D-20, D-21, and D-26) and No. 11C Pipe Still vacuum hot well (D-300) according to the following:

The Permittee shall not emit any noncondensable volatile organic compounds from the condensers, hot wells or accumulators of any vacuum producing systems at a petroleum refinery.

(b) Pursuant to 326 IAC 8-4-2(2), the Permittee shall equip the wastewater (oil/water) separators Tank 8 and Tank 8a, any forebay, and openings in covers with lids or seals such that the lids or seals are in the closed position at all times except when performing maintenance.

D.1.~~7~~**8** Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14][40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ] [326 IAC 12]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF:

(1) The Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(2) The Permittee shall operate tank 3030 in accordance with the requirements in Sections E.1 and E.3 by complying with the requirements in Section E.9, except as provided for in 40 CFR 63.640(n)(8) and listed in Section E.1.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

~~D.1.8 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply the requirements specified in Section E.20 for process heaters H-1X, H-2, H-3, H-200, H-300, which comprise the affected source for the large gaseous fuel subcategory.~~

Compliance Determination Requirements

D.1.9 Operating Requirement

(a) Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002, effective June 1, 2003, fuel oil shall not be used as a fuel for the Nos. 11A and 11C Pipe Stills.

(b) In order to demonstrate compliance with Condition D.1.2, following the installation of the low-NOx burners the heater H-200 shall operate using only low-NOx burners.

(c) Compliance with the limits in Condition D.1.2(b)(2) shall be demonstrated as specified in Condition D.0.3.

(d) In order to demonstrate compliance with Condition D.1.2, following the startup of New Coker (#2 Coker), the pressure relief discharge that was previously routed to the blowdown stacks will be routed to the DDU flare, except for T-300 vacuum tower relief discharge and the COV's. The flare must be operated with a flame present at all times that 11A PS or 11C PS is in operation.

D.1.10 Operating Requirement

Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition ~~D.1.2~~ **D.1.3** shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

D.1.11 Continuous Emissions Monitoring

In order to demonstrate compliance with Condition D.1.2, the Total Reduced Sulfur continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for H-1X, H-2, H-3, H-200 and H-300 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.1.12 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.1.13 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions **D.1.3 and D.1.9** ~~D.1.2 and D.1.9~~, the Permittee shall maintain a daily record of the following for Nos. 11A and 11C Pipe Stills:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.1.1, Permittee shall maintain records for the Nos. 11A and 11C Pipe Still process heaters as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.1.5** ~~D.1.4~~, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.1.6(a)** ~~D.1.5(a)~~, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR Plan.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.1.6(b)** ~~D.1.5(b)~~, the Permittee shall keep records as specified in Section E.1 and E.4.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.1.8(a)(1)** ~~D.1.7(a)(1)~~, the Permittee shall keep records as specified in Sections E.1 and E.3.

(g) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.1.8(a)(2)** ~~D.1.7(a)(2)~~, the Permittee shall keep records as specified in Sections E.1, E.3, and E.9.

(h) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.1.8(b)** ~~D.1.7(b)~~, the Permittee shall keep records as specified in Section E.6.

(i) In order to demonstrate compliance with Condition D.1.2, the Permittee shall maintain records of monthly firing rates and SO2 emissions for H-1X, H-2, H-3, H-200, and H-300.

(j) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.1.2, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.1.14 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions **D.1.3, D.1.4 and D.1.9** ~~D.1.2, D.1.3 and D.1.9~~, the Permittee shall submit a report to the IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour for Nos. 11A and 11C Pipe Still process heaters.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.1.5** ~~D.1.4~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.1.6(a)** ~~D.1.5(a)~~, the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.1.6(b)** ~~D.1.5(b)~~, the Permittee shall submit records as specified in Section E.1 and E.4.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.1.8(a)(1)** ~~D.1.7(a)(1)~~, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.1.8(a)(2)** ~~D.1.7(a)(2)~~, the Permittee shall submit reports as specified in Sections E.1, E.3, and E.9.

(g) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.1.8(b)** ~~D.1.7(b)~~, the Permittee shall submit reports as specified in Section E.6.

(h) In order to demonstrate compliance with Condition D.1.2, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions for heaters H-200, H-300, H-1X, H-2, and H-3 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(i) Pursuant to 326 IAC 3-5-7 and to document compliance with Condition D.1.2 and D.1.11, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.2 FACILITY OPERATION CONDITIONS - No. 11B Coker and Coke Pile and New Coker (#2 Coker)

Facility Description [326 IAC 2-7-5(15)]

No. 11B Coker, which processes heavy crude fractions into coke, and Coke Pile. These facilities are identified as Unit 120 and are rated at 2,000 tons of coke per day. The facility includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Four (4) process heaters comprising:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-101	200 (total)	120-04	None
H-102			
H-103			
H-104			

(2) Storage and handling of the bulk material. Fugitive emissions are controlled by keeping the coke wetted and having a 15' sheet piling wall surrounding the coke pile. The coke pile height will not exceed 15'.

(3) The No. 11B Coker is connected to the DDU flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges and other connectors.

New Coker (#2 Coker), which processes heavy crude fractions into coke, and new Coke Handling System. These facilities are identified as Unit 800 and are rated at 6,000 tons of coke per day. The New Coker (#2 Coker) heaters H-201, H-202, and H-203 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New Coker (#2 Coker) heater stacks have continuous emissions monitors (CEMS) for NOx and CO. The existing Coker and Coke Pile will be replaced as part of the CXHO Project. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) Process heaters comprising:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-201	**208**	**800-01**	**Low-NO_X burners and selective catalytic reduction**
H-202	**208**	**800-02**	**Low-NO_X burners and selective catalytic reduction**
H-203	**208**	**800-03**	**Low-NO_X burners and selective catalytic reduction**

(2) Storage and handling (including up to 10 transfer points) of the bulk material comprised of a partially enclosed crusher, enclosed conveyors, enclosed storage, day bins, and rail car load out under the main operating scenario. In order to minimize fugitive emissions from the coke handling process, transfer points 1 and 10 will include enclosed conveyors and transfer points 2 through 9 will use enclosed buildings, and water sprays. Coke handling operations will be expected to operate under this main operating scenario for at least 95% of operating hours annually.

There will also be an alternative operating scenario which will consist of three enclosed conveyors with unenclosed transfer points. Coke handling operations are expected to operate under this alternate operating scenario for no more than 5% of operating hours annually.

(3) The Coker is connected to the South flare system (included in Section D.35). The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) One (1) storage tank, identified as TK-6255, with a maximum storage capacity of 14,028,000 gallons storing coker resid at a vapor pressure less than 0.5 psia. Tank TK-6255 is equipped with a fixed roof.

(5) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.2.1 Lake County PM10 Emission Limitations [326 IAC 6.8~~-2-6~~]

(a) **Until the shutdown of the No. 11B Coker and Coke Pile and the heaters identified as H-101, H-102, H-103, H-104,** pursuant to **Commissioner's Order No. 2007-01** ~~326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d))~~, PM10 emissions from the stack serving No. 11 pipe still furnaces H-101, H-102, H-103, and H-104 coke preheaters shall not exceed **0.0075 lb/MMBTU and 1.49 lb/hr (total).** ~~0.004 lbs/MMBtu and 0.741 lbs/hr.~~

(b) **Until the shutdown of the No. 11B Coker and Coke Pile and the heaters identified as H-101, H-102, H-103, H-104,** pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

(c) Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from each of the New Coker (#2 Coker) stacks 800-01, 800-02, and 800-03 shall not exceed 0.03 grains per dry standard cubic foot.

D.2.2 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

(a) After the permanent shutdown of No. 11 B Coker and Coke Pile, the throughput of coke processed at the New Coker (#2 Coker) shall not exceed 2,190,000 tons per twelve (12) consecutive month period, with compliance determined at the end of each month and the coke handling operations shall not operate under the alternative operating scenario for more than 438 hours per twelve (12) consecutive month period.

(b) The No. 11B Coker, Coke Pile, and heaters H-101, H-102, H-103, and H-104 shall be permanently shutdown as part of the CXHO project.

For each of the heaters H-201, H-202, and H-203:

(c) The emissions of NOx from each shall not exceed 18.2 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(e) The emissions of SO2 from each shall not exceed 10.1 tons per 12 consecutive month period, with compliance determined at the end of each month.

(f) The emissions of PM and PM-10 each shall not exceed 0.0019 and 0.0081 pounds per million BTU.

(g) The emissions of CO from each shall not exceed 17.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(h) The Permittee shall comply with the following fuel usage limits per twelve (12) consecutive month period, with compliance determined at the end of each month:

Unit ID	Firing rate limit (10^3 mmBTU) per 12 consecutive month period
H-201	1822.1
H-202	1822.1
H-203	1822.1

Compliance with the coker throughput limits and limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

~~D.2.2~~**D.2.3** Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Until the shutdown of the heaters identified as H-101, H-102, H-103, H-104:

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from the H-101, H-102, H-103, and H-104 No. 11B Coker process heaters shall each not exceed 0.033 lbs/MMBtu and the total sulfur dioxide emissions from all four process heaters shall not exceed 6.60 lbs per hour.

D.2.4 Volatile Organic Liquid Storage Vessels [326 IAC 8-9-6]

Pursuant to 326 IAC 8-9-6(b), for storage tank TK-6255, which is used to store liquids with vapor pressures less than 0.5 psia, the Permittee shall comply only with the recordkeeping requirements specified in Condition D.2.16(h).

~~D.2.3~~ **D.2.5** Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

(a) **Until the shutdown of the heaters identified as H-101, H-102, H-103, H-104,** pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the process heaters H-101, H-102, H-103, and H-104 No. 11B.

(b) **Upon startup of New Coker (#2 Coker) heaters H-201, H-202, H-203, Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for process heaters H-201, H-202 and H-203.**

~~D.2.4~~ **D.2.6**Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 12] [40 CFR 60, Subpart GGG**a**]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG**a** and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.**25**, and E.**26**~~13~~ for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.2.7 Hazardous Air Pollutants (HAP)[326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the storage tank TK-6255 shall comply with the requirements under 40 CFR 63.640(l)(3) through l(3), as specified in Section E.1.

~~D.2.5~~ **D.2.8** Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] **[40 CFR 60, Subpart QQQ] [326 IAC 12]**

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) **Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.**

(c) **Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.**

~~D.2.6~~**D.2.9** Lake County Fugitive Particulate Matter Control Requirements [326 IAC 6.8-10]

The Permittee shall comply with the following for the No. 11B Coker and Coke Pile until it is permanently shutdown, and for the New Coker (#2 Coker) and Coke Handling System upon startup:

Pursuant to 326 IAC 6.8-10-3(3)(A), (3)(B), (5), and (6) (formerly 326 IAC 6-1-11.1(d)(3)(A), (3)(B), (5), (6)(A) and (d)(6)(B)), the Permittee shall comply with the opacity limitations in Condition C.6 (Fugitive Dust Emissions) for batch material transfer, wind erosion from storage piles, and material transfer by front end loader and truck. Opacity from the activities shall be determined as follows:

(a) Batch Transfer - The average instantaneous opacity shall consist of the average of three (3) opacity readings taken five (5) seconds, ten (10) seconds, and fifteen (15) seconds after the end of one (1) batch loading or unloading operation. The three (3) readings shall be taken at the point of maximum opacity. The observer shall stand approximately fifteen (15) feet from the plume and at approximately right angles to the plume.

(b) Wind Erosion from Storage Piles - The opacity shall be determined using 40 CFR 60, Appendix A, Method 9, except that the opacity shall be observed at approximately four (4) feet from the surface at the point of maximum opacity. The observer shall stand approximately fifteen (15) feet from the plume and at approximately right angles to the plume. The limitations may not apply during periods when application of fugitive particulate control measures are either ineffective or unreasonable due to sustained very high wind speeds. During such periods, the company shall continue to implement all reasonable fugitive particulate control measures and maintain records documenting the application of measures and the basis for a claim that meeting the opacity limitation was not reasonable given prevailing wind conditions.

(c) Material Transported by Truck or Rail - Compliance with this limitation shall be determined by 40 CFR 60, Appendix A, Method 22, except that the observation shall be taken at approximately right angles to the prevailing wind from the leeward side of the truck or railroad car. Material transported by truck or rail that is enclosed and covered shall be considered in compliance with the inplant transportation requirement.

(d) Material Transported by Front End Loader or Skip Hoist - Compliance with this limitation shall be determined by the average of three (3) opacity readings taken at five (5) second intervals. The three (3) opacity readings shall be taken as follows:

(1) The first will be taken at the time of emission generation.

(2) The second will be taken five (5) seconds later.

(3) The third will be taken five (5) seconds later or ten (10) seconds after the first.

~~D.2.7 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~pursuant to 40 CFR Part 63, Subpart DDDDD, the Permittee shall comply with the requirements in Section E.20 for process heaters H-101, H-102, H-103, and H-104, which comprise the affected source for the large gaseous fuel subcategory.~~

Compliance Determination Requirements

~~D.2.8~~ **D.2.10**Operating Requirement

Until the shutdown of the No. 11B Coker and the associated emissions units:

(a) Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the No. 11B Coker furnaces.

(b) **Compliance with the limits in Condition D.2.2(d) and (f) shall be demonstrated as specified in Condition D.0.3.**

~~D.2.9~~ **D.2.11** Fugitive Dust Control Plan [326 IAC 6.8-10]

(a) **Until the shutdown of the No. 11B Coker and the associated emissions units:**

Pursuant to 326 IAC 6.8-10-4 (formerly 326 IAC 6-1-11.1) ~~and in order to comply with Condition D.2.9,~~ the Permittee shall control fugitive particulate matter emissions **from No. 11B Coker and Coke Pile** according to the Fugitive Dust Control Plan (FDCP), included as Appendix C. If it is determined that the control procedures specified in the FDCP do not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require that the FDCP be revised and submitted for approval.

(b) **Pursuant to 326 IAC 6.8-10-4 (formerly 326 IAC 6-1-11.1), the Permittee shall control fugitive particulate matter emissions from the New Coker (#2 Coker) and Coke Pile according to the updated Fugitive Dust Control Plan (FDCP) submitted on January 30, 2008, included as Appendix C. If it is determined that the control procedures specified in the FDCP do not demonstrate compliance with the fugitive emissions limitations, IDEM, OAQ may require that the FDCP be revised and submitted for approval.**

~~D.2.10~~ **D.2.12** Operating Requirement

(a) **Until the shutdown of the No. 11B Coker and heaters,** pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition ~~D.2.2~~ **D.2.4** shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) **In order to demonstrate compliance with Condition D.2.2, the Permittee shall operate the heaters H-201, H-202, and H-203 using only low-NOx burners.**

(c) **In order to comply with Condition D.2.2, the SCRs shall be operated as necessary to meet the NOx emissions limits for heaters H-201, H-202 and H-203.**

D.2.13 Continuous Emissions Monitoring

The Total Reduced Sulfur, CO, and NOx continuous emission monitoring systems (CEMS) for H-201, H-202, and H-203 shall be calibrated, maintained, and operated for determining compliance with the SO2, CO and NOx emissions limits in Condition D.2.2 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

D.2.14 PM and PM-10

In order to comply with Condition D.2.2, the Permittee shall use wet suppression to control emissions of PM and PM10 from transfer points 1 through 10 at New Coker (#2 Coker) as necessary to ensure that the coke processed has a moisture content greater than eight percent. The suppressant shall be applied in a manner and at a frequency sufficient to ensure compliance with Condition D.2.2.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

~~D.2.11~~ **D.2.15**Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

~~D.2.12~~ **D.2.16**Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions **D.2.3 and D.2.11** ~~D.2.2, and D.2.8~~, the Permittee shall maintain a daily record of the following for the No. 11B Coker process heaters:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

The Permittee shall comply with this requirement until the shutdown of the No. 11B Coker and the associated emissions units.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.2.1, Permittee shall maintain records for the No. 11B Coker process heaters as specified in the Continuous Compliance Plan. **The Permittee shall comply with this requirement until the shutdown of the No. 11B Coker and the associated emissions units.**

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.2.5** ~~D.2.3~~, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.2.6(a)** ~~D.2.4(a)~~, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC and to document compliance with Condition **D.2.6(b)** ~~D.2.4(b)~~, the Permittee shall keep records as specified in Sections E.1, E.4, and E.13.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.2.8** ~~D.2.5~~, the Permittee shall keep records as specified in Sections E.1 and E.3.

(g) Pursuant to 326 IAC 6.8-10-4(4) (formerly 326 IAC 6-1-11.1(e)(4)) and to document compliance with Condition **D.2.9** ~~D.2.6~~, for the Coke Pile, the Permittee shall keep the following documentation:

(1) A map or diagram showing the location of all fugitive PM emission sources controlled,

(2) For application of physical or chemical control agents, the following:

(A) The name of the agent

(B) Location of application

(C) Application rate

(D) Total quantity of agent used

(E) If diluted, percent of concentration

(F) The material data safety sheets for each chemical

(3) A log recording incidents when control measures were not used and a statement of explanation.

(4) Copies of all records required by this section shall be submitted to IDEM, OAQ within twenty (20) working days of a written request by IDEM, OAQ.

(h) Pursuant to 326 IAC 8-9-6(b), the Permittee shall maintain, for the life of the vessel, a record of the following for tank TK-6255 to which 326 IAC 8-9 applies:

(1) The vessel identification number,

(2) The vessel dimensions,

(3) The vessel capacity, and

(4) A description of the emission control equipment for each vessel described in section 4(a) or 4(b) of 326 IAC 8-9, or a schedule for installation of emission control equipment on vessels described in section 4(a) or 4(b) of 326 IAC 8-9 with a certification that the emission control equipment meets the applicable standards.

(i) In order to demonstrate compliance with Condition D.2.2, the Permittee shall maintain records of monthly firing rates and CO, NOx, and SO2 emissions for heaters H-201, H-202, and H-203.

(j) In order to demonstrate compliance with Condition D.2.2, the Permittee shall maintain records of monthly coke throughput at the New Coker (#2 Coker).

(k) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.2.13 the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

~~D.2.13~~ **D.2.17**Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions **D.2.3 and D.2.10** ~~D.2.2, and D.2.8~~, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the No. 11B Coker process heaters. **The Permittee shall comply with this requirement until the shutdown of the No. 11B Coker and the associated emissions units.**

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.2.5 ~~D.2.3~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.2.6(a)** ~~D.2.4(a)~~, the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC and to document compliance with Condition **D.2.6(a)** ~~D.2.4(b)~~, the Permittee shall submit reports as specified in Sections E.1, E.4, and E.13.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.2.8** ~~D.2.5~~, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(f) Pursuant to 326 IAC 6.8-10-4(4)(G) (formerly 326 IAC 6-1-11.1(e)(4)(G)) and to document compliance with Condition **D.2.11** ~~D.2.9~~, a quarterly report shall be submitted within thirty (30) days of the end of each quarter, stating the following:

(1) The dates any required control measures were not implemented

(2) A listing of those control measures

(3) The reasons that the control measures were not implemented

(4) Any corrective action taken

(g) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.2.2 and D.2.13, the Permittee shall submit reports of excess SO2, CO and NOx emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments.

(h) In order to demonstrate compliance with Condition D.2.2, the Permittee shall submit quarterly reports for the monthly firing rates, and CO, NOx, and SO2 emissions at heaters H-201, H-202, and H-203. The report submitted by the Permittee does require the certification by the "Responsible Official" as defined by 326 IAC 2-7-1(34).

(i) In order to demonstrate compliance with Condition D.2.2, the Permittee shall submit quarterly reports for the coke throughput at the New Coker (#2 Coker) and the number of hours the coke handling operated under alternative operating scenario. The report submitted by the Permittee does require the certification by the "Responsible Official" as defined by 326 IAC 2-7-1(34).

SECTION D.3 FACILITY OPERATION CONDITIONS – No. 12 Pipe Still

Facility Description [326 IAC 2-7-5(15)]

(c) No. 12 Pipe Still, constructed in 1959, **to be modified as part of the CXHO Project**, which processes crude into various hydrocarbon fractions based on boiling points, identified as Unit ID 130, and is rated at 336,000 barrels per day. **Heaters identified as H-1AN, H-1AS, H-1B, H-2, H-1CN, H-1CS, and H-1CX will be shutdown and replaced by heaters H-101A, H-101B, and H-102 as part of the CXHO project.** The facility includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) The following process heaters, all of which are fired by natural gas, refinery gas, or liquified petroleum gas:

Heater Identification	Construction Date/Permitted Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
H-1AN	1959	121.5	130-01	None
H-1AS	1959	121.5	130-01	None
H-1B	1959	243	130-01	None
H-2	1959	174	130-01	Ultra low NO_x burners
H-1CN	1967/1995	120	130-02	Low NO_x burners
H-1CS	1967	a	b	None
H-1CX	1977	410	130-04	Low NO_x burners
H-101A	**Permitted in 2008**	**355**	**130-05**	**Ultra low-NO_X burners**
H-101B	**Permitted in 2008**	**355**	**130-07**	**Ultra low-NOx burners**
H-102	**Permitted in 2008**	**331**	**130-06**	**Ultra low-NO_X burners**

[a] No longer in service -- was rated at 120 MMBtu/hour.
[b] No longer in service -- was exhausted to stack 130-03.

(2) One (1) vacuum hot well, identified as D-7, constructed in 1995, and venting to S/V 130-05. The vacuum tower overhead system consists of a series of condensers, steam ejectors, and vacuum pumps. The majority of the overhead vapors are condensed and drained to the hotwell, which is pumped back to the front end of the unit for reprocessing. The gas compressors pull the remaining vapor that is not condensed in the overhead system into the wet gas system, where the hydrocarbon is reprocessed by down stream units. A thermocouple system (with temperature alarm) is used to monitor the vacuum on the system.

(3) Leaks from process equipment, including compressors (K-1, K-1A, and K-1B), valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and flanges.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.3.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)), the Permittee shall comply with the following PM_{10} emission limitations for the No. 12 Pipe Still process heaters **until these heaters are shutdown as part of the CXHO project**:

Process Heater	PM_{10} Limit (lbs/MMBtu)	PM_{10} Limit (lbs/hour)
Stack serving H-1AN, H-1AS, H-1B Preheaters and H-2 Vacuum Heater	0.025	16.348
~~H-1CN Crude Preheater~~	~~0.004~~	~~0.444~~
H-1CS Crude Preheater **(no longer in service)**	0.004	0.444
~~H-1CX Crude Preheater~~	~~0.004~~	~~0.924~~

(b) Until the shutdown of heaters H-1CN and H-1CX, pursuant to Commissioner's Order No. 2007-01, the PM_{10} emissions from H-1CN and H-1CX shall not exceed 0.0075 lb/MMBTU for both heaters and 0.894 and 3.055 lb/hr for H-1CN and H-1CX, respectively.

~~(b)~~**(c)** Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition **(until shutdown)** in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.3.2 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from each of the three (3) heaters H-101A, H-101B and H-102 shall not exceed 0.03 grains per dry standard cubic foot.

D.3.~~2~~**3** Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, the Permittee shall comply with the following sulfur dioxide emission limitations for the No. 12 Pipe Still process heaters **until these heaters are shutdown**:

Process Heater	SO_2 Limit(lbs/MMBtu)	SO_2 Limit(lbs/hour)
H-1AS and H-1AN Preheaters	0.033	21.78
H-1B Preheater	0.033	
H-2 Vacuum Heater	0.033	
H-1CN Crude Preheater	0.033	7.92
H-1CS Crude Preheater	0.033	
H-1CX Crude Preheater	0.033	13.53

D.3.~~3~~**4** Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

(a) Pursuant to SPM 089-15202-00003, issued on April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for following process heaters (**until heaters H-1AS and H-1AN Preheaters, H-1B Preheater, H-2 Vacuum Heater, H-1CN Crude Preheater, H-1CS Crude Preheater, and H-1CX Crude Preheater are shutdown)**: H-1AS and H-1AN Preheaters, H-1B Preheater, H-2 Vacuum Heater, H-1CN Crude Preheater, H-1CS Crude Preheater, and H-1CX Crude Preheater.

(b) **Pursuant to 40 CFR 60.140(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the following heaters upon startup: H-101A, H-101B, H-102.**

D.3.~~4~~**5** ~~Nitrogen Oxides (NO_x)~~ Emission Offset **[326 IAC 2-3], Prevention of Significant Deterioration [326 IAC 2-2] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits**

(a) Pursuant to CP 089-2055-00453 issued on March 12, 1992, nitrogen oxide emissions from the 12 Pipe Still H-1CX furnace shall not exceed 0.10 lb/MMBtu. ~~This is equivalent to 180 tons per year.~~ Compliance with this limit renders 326 IAC 2-3 not applicable. The H-1CX furnace shall also be equipped with low NO_x burners.

In order to render 326 IAC 2-2-8, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable:

(b) The Permittee shall comply with the following limits for the heaters identified as H-101A, H-101B and H-102, with compliance with the annual NOx, CO, and SO2 limits determined at the end of each month):

Heater ID	NOx tons per 12 consecutive month period	SO2 tons per 12 consecutive month period	CO tons per 12 consecutive month period)	VOC (lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
H-101A	77.7	17.2	29.5	0.0054	0.0019	0.0075
H-101B	77.7	17.2	29.5	0.0054	0.0019	0.0075
H-102	72.5	16.0	27.5	0.0054	0.0019	0.0075

(c) The Permittee shall comply with the following limits on firing rates:

Unit ID	Firing rate limit (10^3 mmBTU) per 12 consecutive month period
H-101A	3109.8
H-101B	3109.8
H-102	2899.6

(d) The heaters H-1AN, H-1AS, H-1B, H-2, H-1CN, and H-1CX shall be permanently shutdown prior to the start-up of the new Coker (#2 Coker).

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.3.~~5~~**6** Equipment Leaks of VOC and Hazardous Air Pollutants (HAPs)[326 IAC 12] [326 IAC 8-4-8] [40 CFR 60, Subpart GGG**a**] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG**a** and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.**25**4, and E.**26**~~13~~ for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.3.~~6~~**7** Volatile Organic Compounds (VOC) [326 IAC 8-4-2]

Pursuant to 326 IAC 8-4-2(1), the Permittee shall control VOC emissions from No. 12 Pipe Still vacuum hot well, D-7, according to the following:

No owner or operator of any vacuum producing systems at a petroleum refinery may cause, allow or permit the emission of any noncondensable volatile organic compounds from the condensers, hot wells or accumulators of the system.

D.3.~~7~~**8** Wastewater / Waste Streams [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ] [326 IAC 12]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

~~D.3.8 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements in Section E.20 for the process heaters H-1AN, H-1AS, H-1B, H-2, H-1CN and H-1CX, which comprise the affected source for the large gaseous fuel subcategory: process heaters H-1AN, H-1AS, H-1B, H-2, H-1CN, and H-1CX.~~

D.3.9 Prevention of Significant Deterioration (PSD) **Minor Limit** [326 IAC 2-2]

Pursuant to SPM 089-15202-00003, issued April 24, 2002 and SPM 089-18588-00453, issued July 15, 2004, nitrogen oxide emissions from the Heater H-2 **(until shutdown)** shall be controlled by low-NOx burners having an emission rate of 0.044 pounds per million Btu or less. ~~This limit equates to a potential to emit 33.53 tons of nitrogen per year for Heater H-2.~~ This condition renders the requirements of 326 IAC 2-2 not applicable.

Compliance Determination Requirements

D.3.10 Operating Requirement

(a) Pursuant to SPM 089-15202-00003, issued April 24, 2002, fuel oil shall not be used as fuel for the No. 12 Pipe Still.

(b) In order to demonstrate compliance with Condition D.3.5(b), the heaters H-101A, H-101B, and H-102 shall operate using ultra-low NOx burners only.

(c) Compliance with the lb/mmBTU limits in Condition D.3.5(b) shall be demonstrated as specified in Condition D.0.3.

D.3.11 Continuous Emissions Monitoring

The Total Reduced Sulfur, NOx, and CO continuous emission monitoring systems (CEMS) for H-101A, H-101B, and H-102 shall be calibrated, maintained, and operated for determining compliance with the SO2, NOx, and CO emissions limits in Condition D.3.5 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

D.3.~~11~~**12**Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

(a) Within 36 months after the effective date of this permit, in order to demonstrate compliance with Condition D.3.4, the Permittee shall perform NO_x testing of the H-1CX heater utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C-Performance Testing.

(b) Within 5 years of last compliant stack test, the Permittee shall perform NO_x testing of the H-2 heater utilizing methods approved by the Commissioner, in order to demonstrate compliance with Condition D.3.9. Testing shall be conducted in accordance with Section C- Performance Testing.

D.3.~~12~~**13**Operating Requirement

Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition ~~D.3.2~~ **D.3.3** shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

D.3.14 Continuous Emissions Monitoring

(a) In order to demonstrate compliance with Conditions D.3.5 and D.3.12, the Total Reduced Sulfur, NOx, and CO continuous emission monitoring systems (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2, NOx, and CO emissions limits for H-101A, H-101B, and H-102 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

(b) In order to demonstrate compliance with Condition D.3.12, the CO continuous emission monitoring systems (CEMS) shall be calibrated, maintained, and operated for demonstrating compliance with the CO emissions limits for H-101A, H-101B, and H-102 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.3.~~13~~**15**Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.3.~~14~~**16**Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions **D.3.3** ~~D.3.2~~, and D.3.10, the Permittee shall maintain a daily record of the following for No. 12 Pipe Still:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each fuel type, and

(5) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.3.1, Permittee shall maintain records for the No. 12 Pipe Still process heaters **H-1AS and H-1AN Preheaters, H-1B Preheater, H-2 Vacuum Heater, H-1CN Crude Preheater, H-1CS Crude Preheater, and H-1CX Crude Preheater** as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.3.4** ~~D.3.3~~, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.3.6(a)** ~~D.3.5(a)~~, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Condition **D.3.6(b)** ~~D.3.5(b)~~, the Permittee shall keep records as specified in Sections E.1, E.4 and E.13.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.3.8** ~~D.3.7~~, the Permittee shall keep records as specified in Sections E.1 and E.3.

(g) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.3.8(b)** ~~D.3.7(b)~~, the Permittee shall keep records as specified in Section E.6.

(h) In order to demonstrate compliance with Condition D.3.5, the Permittee shall maintain records of the monthly firing rates and CO, SO2, and NOx emissions at heaters H-101A, H-101B, and H-102.

(i) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.3.11, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.3.~~15~~**17** Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions **D.3.3** ~~D.3.2~~, and D.3.10 , the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur emission rate, in pounds per hour, for No. 12 Pipe Still process heaters.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.3.4** ~~D.3.3~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.3.6(a)** ~~D.3.5(a)~~, the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC and to document compliance with Condition **D.3.6(b)** ~~D.3.5(b)~~, the Permittee shall submit reports as specified in Sections E.1, E.4, and E.13.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.3.8(a)** ~~D.3.7(a)~~, the Permittee shall submit reports as specified in Sections E.1, and E.3.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.3.8(b)** ~~D.3.7(b)~~, the Permittee shall submit reports as specified in Section E.6.

(g) In order to demonstrate compliance with Condition D.3.5, upon start-up of the H-101A, H-101B and H-102 heaters, the Permittee shall submit a quarterly summary of the monthly firing rates, and CO, NOx, and SO2 emissions for heaters H-101A, H-101B, and H-102 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(h) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.3.5 and D.3.11, the Permittee shall submit reports of excess SO2, NOx and CO emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.4 FACILITY OPERATION CONDITIONS - Sulfur Recovery Unit

Facility Description [326 IAC 2-7-5(15)]

(d) The Sulfur Recovery Unit (SRU) Facility, identified as Unit ID 162, originally constructed in 1971 and expanded in 1981 and 1995, and rated at 600 long tons per day **and will be modified as part of the CXHO Project increasing the capacity to 1,300 long tons per day** of sulfur. The facility includes the following and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Three (3) three-stage Claus sulfur recovery trains, identified as A, B, and C**, and two (2) additional three-stage Claus sulfur recovery trains installed after modification, identified as D and E** trains.

(2) One (1) Beavon-Stretford tail gas unit (B/S TGU), a reduction system with a burner capacity of 24.3 MMBtu per hour, exhausting at stack S/V 162-02. **The B/S TGU will be decommissioned as part of the CXHO project.**

(3) One (1) tail gas unit (SBS TGU), an oxidation system with a burner capacity of 40 MMBtu per hour, exhausting at stack 162-04. **The SBS TGU will be decommissioned as part of the CXHO project.**

(4) One (1) caustic soda scrubbing tower to control sulfur dioxide emissions from the SBS TGU. **The caustic soda scrubbing tower will be decommissioned as part of the CXHO project.**

(5) One (1) cooling tower, identified as the SBS cooling tower, to remove sodium bisulfite from the caustic scrubbing tower exhaust stream, equipped with a high-efficiency mist eliminator, and exhausting at stack 162-05. **The SBS cooling tower will be decommissioned as part of the CXHO project.**

(6) Gas quenching and cooling towers other than the SBS cooling tower**, to be decommissioned as part of the CXHO project.**

(7) One (1) quench separator with mist eliminators, **to be decommissioned as part of the CXHO project.**

(8) One (1) gas cooler and water condenser with sulfur dioxide stripper**, to be decommissioned as part of the CXHO project.**

(9) Caustic soda storage tanks and sodium bisulfite storage tanks, and handling equipment **to be decommissioned as part of the CXHO project.**

(10) One (1) standby incinerator, used only in the event of an emergency, exhausting at stack S/V 162-01, **to be decommissioned as part of the CXHO project.**

(11) One (1) flare stack exhausting at stack S/V 162-03 which controls H_2S and VOC emissions during emergency situations, unit start-ups/shut-downs, and preparation of equipment for maintenance. Refinery or natural gas is used as a constant purge stream. Pilot gas is natural gas.

(12) One (1) modular degassing unit, which removes gases that are emitted during the cooling of molten sulfur. Removed gases are vented to the SBS TGU. **Removed gases will be vented to the front-end of Claus Trains D and/or E as part of the CXHO project.**

(13) Two (2) modular degassing units, to be installed as part of the CXHO project, which remove gases that are emitted during the cooling of molten sulfur. The gases will be vented to the front-end of Claus Trains D and/or E as part of the CXHO project.

~~(13) One (1) sour water tank, identified as TK-431, with a maximum storage capacity of 845,600 gallons and used to store a material that has a vapor pressure of less 0.5 psia. The tank was constructed in 1985 and is equipped with an external floating roof.~~

(14) Three (3) sulfur pits, (Sulfur Pits A, B, and C) used to store molten sulfur with their vent stacks routed to the B/S TGU and/or the SBS. As part of the CXHO project, the vents from the sulfur pits A, B and C will be routed to either COT 1 and/or COT 2.

(15) Two (2) sulfur pits (Sulfur Pits D and E), to be installed as part of the CXHO project, used to store molten sulfur and the vents routed to either COT 1 and/or COT 2.

(16) One (1) sour water tank, identified as TK-431, with a maximum storage capacity of 845,600 gallons and used to store a material that has a vapor pressure of less 0.5 psia. The tank was constructed in 1985 and is equipped with an external floating roof.

(17) One (1) sour water storage tank, identified as TK-410, permitted in 2008, having a maximum storage capacity of 4,351.200 gallons and equipped with an external floating roof. The maximum true vapor pressure of the material stored in this tank is less than 0.5 psia.

(18) Two (2) Claus Offgas Treaters (COT), identified as COT1 and COT2, to be installed as part of the CXHO project, thermal oxidation systems which combust natural gas, each rated at 72 mmBTU/hr, equipped with SO2 and CO CEMS, exhausting at stacks S/V 162-06 and 162-07.

(19) Two (2) sulfur storage tanks, identified as SH-1 and SH-2, each with a maximum storage capacity of 1,008,000 gallons and used to store molten sulfur exhausting to stacks S/V 163-09 and 162-10. These tanks will be constructed as part of the CXHO Project and are both fixed roof tanks controlled by a caustic scrubber.

Main Operating Scenario **Pre-CXHO:**
Approximately 80% of tail gases from the three trains are sent to the B/S TGU, with the remainder sent to the SBS TGU.

Alternate Operating Scenario #1 **Pre-CXHO:**
One train and the B/S TGU are not operate. Tail gases from the other two trains are sent to the SBS TGU.

Alternate Operating Scenario #2 **Pre-CXHO:**
The B/S TGU is not operated. Tail gases from the three trains are sent to the SBS TGU.

Alternate Operating Scenario #3 Pre-CXHO:
The SBS TGU is not operated. Tailgases from the three trains are sent to the B/S TGU.

Main Operating Scenario Post-CXHO:
The tail gases from the five trains are sent to both of the COTs.

Alternate Operating Scenario #1 Post-CXHO:

One of the COTs is not operated and the tail gases from the five trains are sent to the other COT.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.4.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from SBS TGU **(until shutdown)**, **each of the two (2) offgas treaters/thermal oxidizers identified as COT1 and COT2,** and the SBS cooling tower **(until shutdown)** shall not exceed 0.03 grains per dry standard cubic foot.

D.4.2 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to **Commissioner's Order No. 2007-01, until it is shutdown, the PM10 emissions from the B/S TGU shall not exceed 0.0075 lb/MMBTU and 0.182 lb/hr.** ~~326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)), emissions for the following Sulfur Recovery Unit process units shall comply with the following emission limitations:~~

~~Emission Unit~~	~~PM_{10} Limit (lbs/MMBtu)~~	~~PM_{10} Limit (lbs/ton of Feed)~~	~~PM_{10} Limit (lbs/hour)~~
~~Sulfur Recovery Unit Incinerator~~	~~0.004~~	~~None~~	~~0.090~~
~~Beavon Stretford Tail Gas Unit (B/S TGU)~~	~~None~~	~~0.110~~	~~0.103~~

(b) Pursuant to Commissioner's Order No. 2007-01, the PM10 emissions from the Sulfur Recovery Unit Incinerator, until it is shutdown, shall not exceed 0.0075 lb/MMBTU and 0.285 lb/hr.

~~(b)~~ **(c)** Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP)**, until the B/S TGU and Sulfur Recovery Unit Incinerator are shutdown**. Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.4.3 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

(a) Pursuant to 326 IAC 7-4.1-3(a)(15), (16) and (17), emissions from the following Sulfur Recovery Unit process units shall comply with the following sulfur dioxide emission limitations:

Unit Description	**SO_2 Emission Limitation (lbs/MMBtu)**	**SO_2 Emission Limitation (lbs/hour)**
Sulfur Recovery Unit Incinerator **(until shutdown)**	0.033	1.25
Beavon Stretford Tail Gas	None	53.10 Total Reduced

Unit Description	SO_2 Emission Limitation (lbs/MMBtu)	SO_2 Emission Limitation (lbs/hour)
Unit (B/S TGU) **(until shutdown)**		Sulfur calculated as SO_2
Sodium Bisulfite Tail Gas Unit (SBS TGU) **(until shutdown)**	None	9.0

(b) Pursuant to 326 IAC 7-4.1-1, the offgas treaters/thermal oxidizers identified as COT1 and COT2 shall burn natural gas only as supplemental fuel.

D.4.4 **Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR and** Emission Offset [326 IAC 2-3] **Minor Limit**

(a) Pursuant to Construction Permit 089-3323-00003, issued December 14, 1994:

(1) Emissions of TRS calculated as SO_2 from the B/S TGU **(until shutdown)** shall not exceed 232.6 tons per twelve (12) consecutive month period.

(2) Emissions of TRS calculated as SO_2 from the B/S TGU **(until shutdown)** shall be limited to 300 parts per million by volume (ppmv).

(3) The following emission units shall remain inoperative unless new approval is obtained:

(A) Propane Dewaxing Unit

(B) #1, #2, and #3 Asphalt Oxidizers

(C) The Butamer Unit

(D) The F-7 Furnace to the Isomerization Unit

(E) The #1 Power Station Boiler #1

(b) Pursuant to SSM 089-13846-00003, issued on June 27, 2001, emissions of SO_2 at 0% excess air from the SBS TGU **(until shutdown)** shall not exceed 39.4 tons per twelve (12) consecutive month period.

Compliance with ~~these~~ conditions **(a) and (b) above shall** render~~s~~ the requirements of 326 IAC 2-3 (Emission Offset) not applicable.

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(c) The PM and PM-10 emissions from COT1 and COT2 shall not exceed 0.0019 and 0.0075 pounds per million BTU, respectively.

(d) The VOC emissions from COT1 and COT2 shall not exceed 0.0054 pounds per million BTU.

(e) The combined SO2 emissions from COT1 and COT2 shall not exceed 194.8 tons per 12 consecutive month period, with compliance determined at the end of each month.

(f) The combined CO emissions from COT1 and COT2 shall not exceed 55.0 tons per 12 consecutive month period, with compliance determined at the end of each month.

(g) The NOx emissions from COT1 and COT2 shall not exceed 0.08 pounds per million BTU.

(h) The Permittee shall comply with the following firing rate limit:

Unit ID	Firing Rate (10^3 mmBTU) per 12 consecutive month period
COT1 and COT2 (total)	1261.4

(i) The B/S TGU, SBS TGU, and SBS Cooling tower shall be permanently shutdown prior to the startup of the new Coker (#2 Coker).

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.4.5 New Source Performance Standards [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(2), the Permittee shall comply with the requirements in Section E.2 for the SBS TGU **(until shutdown)**, **COT1 and COT2 offgas treaters/thermal oxidizers** and B/S TGU **(until shutdown)**.

D.4.6 Equipment Leaks of VOC [326 IAC 8-4-8

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

D.4.7 Wastewater [326 IAC 12] [40 CFR 60, Subpart QQQ]

Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

D.4.8 Requirements for 40 CFR Part 63, Subpart UUU

Pursuant to 40 CFR 63, Subpart UUU, the Sulfur Recovery Unit and associated bypass lines shall comply with the requirements of Section E.10.

Compliance Determination Requirements

D.4.9 Operating Requirements

(a) Pursuant to permit SSM 089-13846-00003 issued June 27, 2001 as amended by Administrative Amendment 089-15525-00003 issued April 15, 2002, the Permittee shall re-route all **NSPS SRP** sulfur pit emissions such that they are treated, monitored, and included as part of the emissions of the SRU **subject to the NSPS Subpart J limit for SO2.**

(b) Compliance with the limits in Conditions D.4.4(c),(d) and (g) shall be demonstrated as specified in Condition D.0.3.

D.4.10Testing Requirements [326 IAC 2-7-6(1), (6)] [326 IAC 2-1.1-11]

Within 3 months of the issuance of this permit and in order to demonstrate compliance with Condition D.4.1, the Permittee shall perform testing of the total dissolved solids (TDS) in the SBS cooling tower utilizing methods as approved by the Commissioner. The SBS tower will be deemed in compliance with 326 IAC 6.8-1-2 provided that the total dissolved solids in the cooling tower water do not exceed 3300 ppmv. This test shall be repeated at least once every three months from the date of this valid compliance demonstration.

D.4.~~11~~**11**Operating Requirement

Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitation for the SRU incinerator in Condition D.4.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

D.4.12 Continuous Emissions Monitoring

In order to demonstrate compliance with Condition D.4.4, the SO2 and CO continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for COT1 and COT2 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.4.~~12~~**13**Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.4.~~13~~**14**Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Condition D.4.3, the Permittee shall maintain daily records of the following for the SRU incinerator for each day that the unit is operated:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.4.2, the Permittee shall maintain records for the SRU as specified in the Continuous Compliance Plan.

(c) Pursuant to 326 IAC 7-4.1-3(b)(1)(C) and to document compliance with Condition D.4.3, the Permittee shall maintain daily records of the following for the B/S TGU:

(1) total reduced sulfur concentration,

(2) hydrogen sulfide concentration, and

(3) calculated stack gas flow rates.

(d) Pursuant to 326 IAC 7-4.1-3(b)(1)(D) and to document compliance with Condition D.4.3, the Permittee shall maintain daily records of the following for the SBS TGU:

(1) sulfur dioxide concentration, and

(2) stack gas flow rate.

(e) To document compliance with Condition D.4.4(a), the Permittee shall keep the following records for the B/S TGU:

(1) one-minute block averages from the TRS CEM, and

(2) average TRS emission rates, calculated as SO_2, per twelve (12) consecutive month period.

(f) To document compliance with Conditions D.4.4(b), the Permittee shall keep the following records for the SBS TGU:

(1) one-minute block averages from the SO_2 CEM, and

(2) average SO_2 emission rate per twelve (12) consecutive month period.

(g) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.4.5, the Permittee shall maintain the records specified in Section E.2.

(h) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.4.6, the Permittee shall keep records as specified in the LDAR plan.

(i) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.4.7, the Permittee shall keep records as specified in Section E.6.

(j) Pursuant to 326 IAC 8-9-6 (Volatile Organic Liquid Storage Vessels), the Permittee shall maintain records of the following information for storage tank TK-431:

(1) The vessel identification number.

(2) The vessel dimensions.

(3) The vessel capacity.

The Permittee shall keep all records as described in (1) through (3) for the life of the vessel.

(k) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.4.12, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.4.~~14~~**15** Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Condition D.4.3, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the following information:

(1) average daily sulfur emission rate, in pounds per hour, for the SRU incinerator;

(2) the average daily sulfur dioxide emission rate for the incinerator and B/S TGU, in terms of pounds per hour of sulfur dioxide; and

(3) the average daily total reduced sulfur emission rate, calculated as sulfur dioxide, for the SBS TGU in pounds per hour.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.4.5, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.4.6, the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the standard operating procedures (SOP) submitted to OAQ for the continuous emission monitors, updates shall be submitted biennially.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.4.7, the Permittee shall submit reports as specified in Section E.6.

~~(f)~~ **Until the B/S TGU and SBS are shutdown, a** ~~A~~ quarterly summary of the information to document compliance with Condition D.4.4 shall be submitted to the address listed in Section C - General Reporting Requirements, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

(~~g~~ **f**) Pursuant to 40 CFR 63, Subpart UUU and to demonstrate compliance with Condition D.4.8, the Permittee shall submit to IDEM, OAQ the documents specified in Condition E.10.

(g) In order to demonstrate compliance with Condition D.4.4, upon start-up of COT 1 and/or COT 2, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions at COT1 and COT2 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(h) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.4.4 and D.4.12, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments.

SECTION D.5 FACILITY OPERATION CONDITIONS - Vapor Recovery Units 100 and 200

Facility Description [326 IAC 2-7-5(15)]:

(e) (1) Vapor Recovery Unit 100 (VRU-100) identified as Unit ID 241, and Vapor Recovery Unit 200 (VRU-200) identified as Unit ID 231**, permitted for turnaround (TAR) in 2008 to repair or replace tower trays and increase existing pumping and cooling capacities.** Gasoline and lighter products from the FCUs are separated in the VRUs using a series of distillation towers. The VRUs are connected to flare stack S/V 241-01, the VRU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes leaks from process equipment including one (1) compressor (identified as J-3E located at VRU-100), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system. The facility may ~~also~~ include insignificant activities listed in Section A.4 of this permit.

(2) As part of the VRU 100/200 Whiting Atmospheric Relief Project (WARP), permitted in 2008, the pressure relief discharges that vented to the existing VRU 100/200 vent stack are being re-routed to the VRU flare.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.5.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

D.5.2 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.5.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) After the startup of the New Coker (#2 Coker), the vent stack for VRU 100 and VRU 200 shall be permanently shutdown and the pressure relief discharges that were routed to the vent stack will be routed to the VRU flare

Compliance Determination Requirements

D.5.4 Operating Requirement

In order to demonstrate compliance with Condition D.5.3, following the startup of New Coker (#2 Coker), the pressure relief discharges from VRU 100 and VRU 200 shall be routed to the VRU flare. The flare must be operated with a flame present at all times that VRU 100 or VRU 200 is in operation.

Compliance Monitoring Requirements

D.5.~~3~~**5** Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8] **[40 CFR 60, Subpart GGGa]**

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

(b) Prior to start-up of VRU 100 and VRU 200, BP shall make a determination as to whether 40 CFR Part 60, Subpart GGGa has been triggered by the changes made as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.5.4**6** Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.5.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.5.1(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.5.2, the Permittee shall keep records as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.5.2, the Permittee shall keep records as specified in Section E.6.

D.5.~~5~~**7** Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.5.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.5.1(b), the Permittee shall submit reports as specified in Section E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.5.2, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.5.2, the Permittee shall submit reports as specified in Section E.6.

SECTION D.6 FACILITY OPERATION CONDITIONS - Vapor Recovery Units 300 and 400

Facility Description [326 IAC 2-7-5(15)]:

(f) **(A)** The Vapor Recovery Unit 300 (VRU 300), identified as Unit ID 150. Light ends and naphtha are separated in the VRU using a series of distillation towers. This unit is connected to flare stack S/V 241-01, the VRU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit:

(1) One (1) off-gas knock out drum (D-400) which exhausts to flare stack S/V 241-01.

(2) Leaks from process equipment, including two (2) compressors (identified as K-340 and K-351), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation system.

(B) Vapor Recovery Unit VRU 400 for the New Coker (#2 Coker), permitted in 2008, to be installed as part of the CXHO project.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.6.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] **[326 IAC 12] [40 CFR 60, Subpart GGGa]**

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC **for VRU 300 and VRU 400** from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems **for VRU 300 and VRU 400**..

(c) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, for VRU 400, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.6.2 Wastewater / Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.6.3 Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Section E.1 for the control of miscellaneous process vent emissions from the off gas knock-out drum (D-400).

This miscellaneous process vent is routed to the VRU Flare. Additional requirements for the VRU Flare are included in Section D.3**5**.~~7~~.

Compliance Monitoring Requirements

D.6.4 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.6.5 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.6.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions D.6.1(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions D.6.3, the Permittee shall keep records as specified in Section E.1.

(d) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.6.2, the Permittee shall keep records as specified in Sections E.1 and E.3.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.6.2, the Permittee shall keep records as specified in Section E.6.

D.6.6 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.6.2(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions D.6.3(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.12.

(c) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions D.6.3, the Permittee shall submit reports as specified in Section E.1.

(d) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.6.2, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.6.2, the Permittee shall submit reports as specified in Section E.6.

SECTION D.8 FACILITY OPERATION CONDITIONS - Propylene Concentration Unit

Facility Description [326 IAC 2-7-5(15)]:

(h) The Propylene Concentration Unit (PCU), identified as Unit ID 145, purifies propylene for sale to chemical plants and eventual manufacture into polypropylene plastic. This unit also has a treating system, which purifies propane. This unit is connected to flare stack S/V 140-01 (the Alky Flare). The flare controls VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The facility includes a caustic degassing drum (D-100) that is vented to flare stack S/V 140-01 and leaks from process equipment, including one compressor (identified as k-104), pumps, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation system. This facility may include insignificant activities listed in Section A.4 of this permit.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.8.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [3267 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Prior to start-up of the new coker (#2 Coker), BP shall make a determination as to whether 40 CFR Part 60 GGGa has been triggered by component changes made on the PCU as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

Compliance Monitoring Requirements

D.8.2 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.8.3 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.8.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.8.1(b), the Permittee shall keep records as specified in Section E.1 and E.4.

D.8.4 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.8.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.8.1(b), the Permittee shall submit reports as specified in Section E.1 and E.4.

SECTION D.9 FACILITY OPERATION CONDITIONS - Isomerization Unit

Facility Description [326 IAC 2-7-5(15)]:

(i) The Isomerization Unit (Isom), identified as Unit ID 210, was constructed in 1985 as a conversion of the No.2 Ultraformer. The Isomerization process converts low octane naphtha into high octane gasoline blending components. This unit is connected to flare stack S/V 220-04, the UIU Flare, to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. **As part of the CXHO Project, the ISOM heater H-1 will be modified by replacing several burners with larger burners, with rated capacity remaining at 190 MMBTU/hr.** The facility includes the following emission sources and may include insignificant activities listed in Section A.4 of this permit.

(1) One (1) natural gas, refinery gas, or liquified petroleum gas-fired Process Heater H-1, **modified as part of CXHO,** rated at 190 MMBtu/hr and vented to stack S/V 210-01.

(2) One (1) Flare Knock-out Drum (D-18) with emissions vented to vessel D-24, which exhausts to flare stack S/V 220-04.

(3) Leaks from process equipment, including one (1) compressor (identified as K1), pumps, valves, process drains and pressure relief devices.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.9.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to **Commissioner's Order No. 2007-01, PM10 emissions from the H-1 Feed Heater Furnace shall not exceed 0.0075 lb/MMBTU and 1.416 lb/hr.** ~~326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)), PM_{10} emissions from the H-1 Feed Heater Furnace shall not exceed 0.004 lb/MMBtu and 0.704 lb/hr.~~

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.9.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3(a)(5), sulfur dioxide emissions from the H-1 Feed Heater Furnace shall not exceed 0.034 lb/MMBtu and 6.46 pounds per hour.

D.9.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for ISOM heater H-1:

(a) The emissions of NOx shall not exceed 0.275 pounds per million BTU.

(b) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(c) The emissions of SO2 shall not exceed 7.4 tons per 12 consecutive month period after the start-up of the new Coker (#2 Coker).

(d) The emissions of PM and PM-10 each shall not exceed 0.0019 and 0.0075 pounds per million BTU, respectively.

(e) The emissions of CO shall not exceed 0.082 pounds per million BTU.

(f) The Permittee shall comply with the following limit on firing rate, following the completion of the CXHO project:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period
ISOM H-1	**1342.03**

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.9.~~3~~**4** Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to SPM 089-15202-00003, issued on April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified E.2 for the H-1 Feed Heater Furnace.

D.9.~~4~~**5** Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs)[326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] **[3267 IAC 12] [40 CFR 60, Subpart GGGa**]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation system.

(c) Prior to start-up of the new coker (#2 Coker), BP shall make a determination as to whether 40 CFR Part 60 GGGa has been triggered by component changes made on the ISOM as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.9.~~5~~**6** Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Section E.1 to control miscellaneous process vent emissions from the off gas knock-out drum (D-18).

This miscellaneous process vent is routed to the UIU Flare. Additional requirements for the UIU Flare are included in Section D.3~~7~~**5**.

D.9.~~6~~**7** Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

~~D.9.7 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements in Section E.20 for the H-1 process heater, which comprises the affected source for the large gaseous fuel subcategory.~~

Compliance Determination Requirements

D.9.8 Operating Requirement

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002, fuel oil shall not be used as fuel for the H-1 Isom Process Heater.

D.9.9 Operating Requirement

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.9.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Compliance with the limits in D.9.3(a), (b), (d) and (e) shall be demonstrated as specified in Condition D.0.3.

D.9.10 Continuous Emissions Monitoring

In order to demonstrate compliance with Condition D.9.3, the Total Reduced Sulfur continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limit from ISOM H-1 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements

D.9.~~10~~**11**Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.9.~~11~~**12**Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.9.2 and D.9.8, the Permittee shall maintain a daily record of the following for the H-1 Process Heater:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.9.1, the Permittee shall maintain records for the H-1 Feed Heater Furnace as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to demonstrate compliance with Condition **D.9.4** ~~D.9.3~~, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.9.5(a)** ~~D.9.4(a)~~, the Permittee shall comply with equipment leak record keeping requirements as specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions **D.9.5(b)** ~~D.9.4(b)~~, the Permittee shall keep records as specified in Sections E.1 and E.4.

(f) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Conditions **D.9.6** ~~D.9.5~~, the Permittee shall keep records as specified in Sections E.1.

(g) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.9.7** ~~D.9.6~~, the Permittee shall keep records as specified in Section E.1 and E.3.

(h) In order to demonstrate compliance with Condition D.9.3, the Permittee shall maintain records of monthly firing rates and SO2 emissions for ISOM H-1.

(i) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.9.10, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.9.~~12~~**13**Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.9.2 and D.9.8, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the H-1 Process Heater.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.9.4** ~~D.9.3~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.9.5(a)** ~~D.9.4(a)~~, the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.9.5(b)** ~~D.9.4(b)~~, the Permittee shall submit reports as specified in Sections E.1 and E.4.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.9.6** ~~D.9.5~~, the Permittee shall submit reports as specified in Section E.1.

(f) In order to demonstrate compliance with Condition D.9.3, the Permittee shall submit a quarterly summary of monthly firing rates and SO2 emissions for ISOM H-1 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(g) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.9.3 and D.9.10, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.10 FACILITY OPERATION CONDITIONS - Aromatics Recovery Unit

Facility Description [326 IAC 2-7-5(15)]:

(j) The Aromatic Recovery Unit (ARU), identified as Unit ID 242, consists of the ARU 200 section and the ARU 300 section. The primary function is to remove light ends from naphtha to obtain a more desirable reforming feed. Its secondary function is to separate xylene, a chemical feedstock, from the Ultraformer product. The ARU utilizes a series of distillation towers to purify reformer feed and another set of towers to separate chemical feedstocks**.** The ARU includes the following process units and may ~~also~~ include insignificant activities listed in Section A.4 of this permit.

(1) The following process heaters, which are fired with refinery gas, natural gas or liquified petroleum gas.

Heater Identification	Construction Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-200A	1978	249.5	242-01	None
F-200B	1978	249.5	242-02	None

(2) The ARU is connected to the 4UF flare stack, S/V 224-06. The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(3) Leaks from process equipment.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.10.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to **Commissioner's Order No. 2007-01** ~~326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(d)),~~ PM_{10} emissions from the following ARU combustion units shall not exceed the following emission limitations:

Process Heater	PM_{10} Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
F-200A	**0.0075** ~~0.004~~	**1.86** ~~0.924~~
F-200B	**0.0075** ~~0.004~~	**1.86** ~~0.924~~

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.10.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3(a)(8), sulfur dioxide emissions from the ARU combustion units, F-200A and F-200B, shall not exceed 0.035 pounds per MMBtu and a total for both F-200A and F200B of 17.47 pounds per hour.

D.10.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for heaters F-200A and F-200B:

(a) The emissions of NOx shall not exceed 0.275 pounds per million BTU.

(b) The emissions of CO shall not exceed 0.082 pounds per million BTU.

(c) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(d) The emissions of PM and PM-10 shall not exceed 0.0019 and 0.0075 pounds per million BTU, respectively.

(e) The Permittee shall comply with the following limits, following the completion of the CXHO project:

Unit ID	Firing Rate (10^3 mmBTU) per 12 month period	SO2 (tons per 12 consecutive month period)
F-200A	1264.94	7.0
F-200B	1264.94	7.0

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.10.~~3~~**4** Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the F-200A and F-200B Process Heaters.

D.10.~~4~~**5** Equipment Leaks of Volatile Organic Compounds and Hazardous Air Pollutants[326 IAC 8-4-8] [36 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart J] **[326 IAC 12][40 CFR 60, Subpart GGGa]**

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with Sections E.1 and E.4 for the equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation system.

(c) Pursuant to 40 CFR 61, Subpart J, the Permittee shall control benzene leaks from the pumps, pressure relief devices, sampling connection systems, open-ended valves, open-ended lines, and valves in accordance with requirements in Section E.5.

(d) Pursuant to 40 CFR 63.640(p), equipment that is subject to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart J is required only to comply with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

(e) **Prior to start-up of the new coker (#2 Coker), BP shall make a determination as to whether 40 CFR Part 60 GGGa has been triggered by component changes made on the ARU as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered.**

D.10.~~5~~**6** Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil-water separators, and closed-vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

~~D.10.6 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements in Section E.20 for process heaters F-200A and F-200B, which comprise the affected source for the large gaseous fuel subcategory.~~

Compliance Determination Requirements

D.10.7 Operating Requirement

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002 and effective June 1, 2003, fuel oil shall not be used as fuel for the F-200A and F-200B Process Heaters.

D.10.8 Operating Requirement

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.10.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) **Compliance with the limits in D.10.3(a), (b), (c) and (d) shall be demonstrated as specified in Condition D.0.3.**

D.10.9 Continuous Emissions Monitoring

In order to demonstrate compliance with Condition D.10.3(e), the Total Reduced Sulfur continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for F-200A and F-200B in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements

D.10.~~9~~**10** Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.10.~~10~~**11** Recordkeeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and to document compliance with Conditions D.10.2, and D.10.7, the Permittee shall maintain a daily record of the following for the F-200A and F-200B Process Heaters:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.10.1, the Permittee shall maintain records for the process heater F-200A and F-200B as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to demonstrate compliance with Condition **D.10.4** ~~D.10.3~~, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.10.5(a)** ~~D.10.4(a)~~, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) To demonstrate compliance with the equipment leak standards of 40 CFR 63, Subpart CC and to document compliance with Condition **D.10.5(b)** ~~D.10.4(b)~~, the Permittee shall keep records as specified in Sections E.1 and E.4.

(f) Pursuant to 40 CFR 61, Subpart J and to document compliance with Condition **D.10.5(c**) ~~D.10.4(c)~~, the Permittee shall keep records as specified in Section E.5.

(g) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.10.6** ~~D.10.5~~, the Permittee shall keep reports as specified in Sections E.1 and E.3.

(h) In order to demonstrate compliance with Condition D.10.3, the Permittee shall maintain records of the monthly firing rates and SO2 emissions for F-200A and F-200B.

(i) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.10.9, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.10.~~11~~**13**Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.10.2 and D.10.7, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the F-200A and F-200B Process Heaters.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition D.10.4 ~~D.10.3~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.10.5(a)** ~~D.10.4(a)~~, the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.10.5(b)** ~~D.10.4(b)~~, the Permittee shall submit reports as specified in Section E.1 and E.4.

(e) Pursuant to 40 CFR 61, Subpart J and to document compliance with Condition **D.10.5(c)** ~~D.10.4(c)~~, the Permittee shall keep records as specified in Section E.5.

(f) Pursuant to 40 CFR 63, Subpart CC, 40 CFR 61, Subpart FF and to document compliance with Condition **D.10.6** ~~D.10.5~~, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(g) In order to demonstrate compliance with Condition D.10.3, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions at F-200A and F-200B to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(h) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.10.3 and D.10.9, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.11 FACILITY OPERATION CONDITIONS - Blending Oil Unit

Facility Description [326 IAC 2-7-5(15)]:

(k) The Blending Oil Unit (BOU), identified as Unit ID 250, uses hydrogen to convert sulfur to hydrogen sulfide and remove it from distillate and gas oil streams to meet product specifications. The hydrogen sulfide is sent to the Claus Trains for further processing. **As part of the CXHO Project, the BOU heater F-401 will be modified by replacing burners.** The facility includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) One (1) process Furnace F-401, constructed in1972, **and modified as part of CXHO,** which vents to stack ID SV250-01. The furnace is rated at 35 million Btu and is fired by natural gas, refinery gas or liquid petroleum gas.

(2) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.11.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to **Commissioner's Order No. the PM10 emissions from the F-401 process furnace shall not exceed 0.0075 lb/MMBTU and 0.261 lb/hr.** ~~326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)), PM_{10} emissions from the F-401Process Furnace shall not exceed 0.004 lb/MMBtu and 0.130 lb/hour.~~

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.11.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from the F-401 Process Furnace shall not exceed 0.034 lb/MMBtu and 1.19 lbs/hour.

D.11.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for heater F-401:

(a) The emissions of NOx shall not exceed 0.098 pounds per million BTU.

(b) The emissions of CO shall not exceed 0.082 pounds per million BTU.

(c) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(d) The emissions of PM and PM-10 each shall not exceed 0.0019 and 0.0075 pounds per million BTU, respectively.

(e) The Permittee shall comply with the following limits following the completion of the CXHO project:

Unit ID	Firing rate (10^3 mmBTU) per 12 month period	SO2 tons per 12 consecutive month period
F-401	201.48	1.1

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.11.~~3~~**4** Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the F-401 Process Furnace.

D.11.~~4~~**5** Equipment Leaks of Volatile Organic Compounds (VOC) [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

D.11.~~5~~**6** Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC, and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for drains systems subject to the 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for drain systems subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

~~D.11.6 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements specified in Section E.20 for Furnace F-401, which comprise the affected source for the large gaseous fuel subcategory.~~

Compliance Determination Requirements

D.11.7 Operating Requirement

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2003, effective June 1, 2003, fuel oil shall not be used as fuel for the F-401 Process Furnace.

D.11.8 Operating Requirement

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.11.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Compliance with limits in Condition D.11.3(a), (b), (c) and (d) shall be demonstrated as specified in Condition D.0.3.

D.11.9 Continuous Emissions Monitoring

In order to demonstrate compliance with Condition D.10.3, the Total Reduced Sulfur continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for F-401 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements

D.11.~~9~~**10**Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.11.~~10~~**11**Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.11.2, and D.11.7, the Permittee shall maintain a daily record of the following for the F-401 Process Furnace:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.11.1, the Permittee shall maintain records for the F-401 Process Furnace as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to demonstrate compliance with Condition **D.11.4** ~~D.11.3~~, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.11.5(a)** ~~D.11.4(a)~~, the Permittee shall comply with equipment leak record keeping requirements as specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.11.6(a)** ~~D.11.5(a)~~, the Permittee shall keep records as specified in Conditions E.1 and E.3.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.11.6(b)** ~~D.11.5(b)~~, the Permittee shall keep records as specified in Section E.6.

(g) In order to demonstrate compliance with Condition D.11.3, the Permittee shall maintain the records of monthly firing rate and SO2 emissions at F-401.

(h) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.11.9, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.11.~~11~~**12**Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.11.2 and D.11.7, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the F-401 Process Furnace.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.11.4** ~~D.11.3~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.11.5** ~~D.11.4~~, the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC 40 CFR 61, Subpart FF and to document compliance with Condition **D.11.6(a)** ~~D.11.5(a)~~, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.11.6(b)** ~~D.11.5(b)~~, the Permittee shall submit reports as specified in Section E.6.

(f) In order to demonstrate compliance with Condition D.11.3, the Permittee shall submit a quarterly summary of the monthly firing rate and SO2 emissions at F-401 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(g) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.11.3 and D.11.9, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.13 FACILITY OPERATION CONDITIONS - No. 4 Treatment Plant

Facility Description [326 IAC 2-7-5(15)]:

(m) No. 4 Treatment Plant, identified as unit 602, removes disagreeable odors from various naphtha and distillate streams using a catalytic process. This facility has only fugitive emissions and/or other emissions that are considered insignificant. **To be shutdown as part of the CXHO project.**

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.13.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, **until shutdown**, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, **until shutdown**, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

D.13.2 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, **until shutdown**, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil-water separators, and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, **until shutdown**, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), **until shutdown** a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

Compliance Monitoring Requirements

D.13.3 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, **until shutdown** the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.13.4 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.13.1(a), **until shutdown** the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.13.1(b), **until shutdown** the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.13.2(a), **until shutdown** the Permittee shall keep records as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.13.2(b), **until shutdown** the Permittee shall keep records as specified in Section E.6.

D.13.5 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.13.1(a), **until shutdown** the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.13.1(b), **until shutdown** the Permittee shall submit reports as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.13.2(a), **until shutdown** the Permittee shall submit reports as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.13.2(b), **until shutdown** the Permittee shall submit reports as specified in Section E.6.

SECTION D.15 FACILITY OPERATION CONDITIONS - No. 3 Ultraformer Unit

Facility Description [326 IAC 2-7-5(15)]:

(o) The No.3 Ultraformer Unit (No. 3 UF), identified as Unit ID 220, commissioned in 1958. The majority of the unit was shutdown in March 2007, including the H-1, H-2 and F-7 heaters, catalyst filled reactors and the internal scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation steps of the regeneration process. The unit consists of the C-2 Splitter Tower, the D-18 flare gas separator, D-24 knock-out drum and associated piping.

~~used to upgrade low-octane naphtha to gasoline blending material and chemical feedstocks. The reforming section consists of a series of process furnaces and catalyst-filled reactors in which the naphtha is heated and converted from straight chain to aromatic compounds. The reactor products are separated by distillation for further processing or blending into gasoline.~~ The No. 3 Ultraformer is connected to flare stack S/V 220-04, the UIU flare, to control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance and reactor regenerations. The No.3 Ultraformer includes the following sources of emissions and may ~~also~~ include insignificant activities listed in Section A.4 of this permit.

~~(1) Three (3) process heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:~~

~~Heater Identification~~	~~Maximum Heat Input Capacity (MMBTU/hr)~~	~~Stack Exhausted To~~	~~Emission Controls~~
~~H-1 **(to be shutdown as part of CXHO)**~~	~~240~~	~~220-01~~	~~None~~
~~H-2 **(to be shutdown as part of CXHO)**~~	~~185~~	~~220-02~~	~~None~~
~~F-7 **(to be shutdown as part of CXHO)**~~	~~23~~	~~220-03~~	~~None~~
~~Regeneration Furnace~~	~~Not in service~~	~~Not in service~~	~~None~~

(1~~2~~) One (1) flare gas separator (D-18) with emissions vented to vessel D-24, which exhausts to flare stack S/V 220-04.

~~(3) Five (5) catalyst-filled reactors, which are vented to flare stack S/V 220-04 during the initial catalyst depressuring and catalyst purging steps of the regeneration process.~~

~~(4) One (1) internal scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation steps of the regeneration process, which removes HAP emissions.~~

(2~~5~~) Leaks from process equipment, including one (1) compressor (identified as K-1), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

~~**The No. 3 Ultraformer, consisting of emission units listed in (1) through (5) will be shut down as part of the CXHO project.**~~

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

~~D.15.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]~~

~~(a) Pursuant to **Commissioner's Order No. 2007- 01** 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)), the Permittee shall not exceed the following PM_{10} emission limitations for the No. 3 UF process heaters:~~

~~Process Heater~~	~~PM10 Limit (lbs/MMBtu)~~	~~PM10 Limit (lbs/hour)~~
~~H-1~~	~~0.004~~	~~0.852~~
~~H-2~~	~~0.004~~	~~0.685~~
~~F-7~~	~~0.004~~	~~0.085~~
~~Regeneration Furnace (Not in service)~~	~~0.004~~	~~1.537~~

~~D.15.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]~~

~~Pursuant to 326 IAC 7-4.1-3, the Permittee shall comply with the following SO_2 emission limitations for the No. 3 UF process heaters:~~

~~Process Heater~~	~~SO_2 Limit (lbs/MMBtu)~~	~~SO_2 Limit (lbs/hour)~~

D.15.1 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Prior to the start-up of the new Coker (#2 Coker), permanently shutdown No. 3 Ultraformer, including 3UF heaters H-1, H-2, and F-7, and the 3UF Reformer, except for the C-2 splitter tower with associated piping and the D-18 flare gas separator.

Compliance with requirement to shutdown the No. 3 Ultraformer including the heaters H-1, H-2, and F-7 and Reformer, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

~~D.15.34 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]~~

~~Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements of Section E.2 for the H-1 **(until shutdown)**, H-2 **(until shutdown)**, and F-7 **(until shutdown)** Process Heaters.~~

D.15.2 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

D.15.3 Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Section E.1 to control miscellaneous process vent emissions from the off gas knock-out drum (D-18).

This miscellaneous process vent is routed to the UIU Flare. Additional requirements for the UIU Flare are included in Section D.37.

D.15.4 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

~~D.15.7**8** Requirements for 40 CFR Part 63, Subpart UUU~~

~~Pursuant to 40 CFR 63, Subpart UUU, the No. 3 Ultraformer Unit and associated bypass lines shall comply with the requirements of Section E.10.~~

~~D.15.8 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements of Section E.20 for process heaters H-1, H-2, and F-7, which comprise the affected source for the large gaseous fuel subcategory.~~

~~**Compliance Determination Requirements**~~

~~D.15.9Operating Requirement~~

~~Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the H-1, H-2, and F-7 Process Heaters.~~

~~D.15.10Operating Requirement~~

~~Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.15.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.~~

Compliance Monitoring Requirements

D.15.5 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

~~D.15.12 Record Keeping Requirements~~

~~(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.15.2, and D.15.9, the Permittee shall maintain a daily record of the following for the H-1, H-2, and F-7 Process Heaters **(until shutdown)**:~~

~~(1) fuel type,~~

~~(2) average daily sulfur content for each fuel type,~~

~~(3) average daily fuel gravity for each fuel type,~~

~~(4) total daily fuel usage for each type, and~~

~~(5) heat content of each fuel type.~~

~~(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.15.1 the Permittee shall maintain records for the No.3 Ultraformer process heaters as specified in the Continuous Compliance Plan.~~

~~(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.15.4** D.15.3, the Permittee shall maintain the records specified Section E.2.~~

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.15.5(a)** ~~D.15.4(a)~~, the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.15.5(b)** ~~D.15.4(b)~~, the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.15.6** ~~D.15.5~~, the Permittee shall keep records as specified in Section E.1.

(d) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.15.7(a)** ~~D.15.6(a)~~, the Permittee shall keep records as specified in Sections E.1 and E.3.11.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.15.7(b)** ~~D.15.6(b)~~, the Permittee shall keep records as specified in Section E.6.

~~(i) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition **D.15.8** D.15.7, the Permittee shall keep records as specified in Section E.10.~~

D.15.13 Reporting Requirements

(a~~(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.15.2 and D.15.9, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the H-1, H-2, and F-7 Process Heaters.~~

~~(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.15.4** D.15.3, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.~~

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.15.7(a)** ~~D.15.6(a)~~, the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.15.5(b)** ~~D.15.4(b)~~, the Permittee shall submit reports as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.15.6** ~~D.15.5~~, the Permittee shall submit reports as specified in Section E.1.

(d) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.15.7(a)** ~~D.15.6(a)~~, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.15.7(b)** ~~D.15.6(b)~~, the Permittee shall submit reports as specified in Section E.6.

~~(h) Pursuant to 40 CFR 63, Subpart UUU and to demonstrate compliance with Condition **D.15.8** D.15.7, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.10~~

SECTION D.16 FACILITY OPERATION CONDITIONS - No. 4 Ultraformer Unit

Facility Description [326 IAC 2-7-5(15)]:

(p) The No.4 Ultraformer Unit (no. 4 UF), identified as Unit ID 224, built in 1972, upgrades low-octane naphtha to gasoline blending material and chemical feedstocks. The front-end of the unit is a desulfurization section. The reforming section consists of a series of process furnaces and catalyst-filled reactors in which the naphtha is heated and converted from straight chain to aromatic compounds. The reactor products are separated by distillation for further processing or blending into gasoline. A new reactor will be installed as part of the CXHO project.The No. 4 Ultraformer includes the following sources of emissions and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Nine (9) process heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBTU/hr)	Stack Exhausted To	Emission Controls
F-1	68	224-01	None
F-8A	163	224-01	None
F-8B	163	224-01	None
F-2	286	224-02	None
F-3	242	224-03	None
F-4R	137	224-04	None
F-5	99	224-04	None
F-6	49	224-04	None
F-7	52	224-05	None

(2) One (1) flare (identified as the 4UF flare), exhausting at stack S/V 224-06. The 4UF flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance, and reactor regenerations.

(3) Six (6) catalyst-filled reactors, which are vented to flare stack S/V 224-06 during the initial catalyst depressuring and catalyst purging steps of the regeneration process.

(4) Leaks from process equipment, including two (2) compressors (identified as K-1 and K-7), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(5) One (1) caustic scrubbing system, controlling the regeneration vent during the coke burn-off and catalyst rejuvenation process, which removes HAP emissions. The scrubber system includes:

(A) One (1) caustic scrubber exhausting to stack 224-07;

(B) One (1) carbon adsorption system used to treat waste scrubber liquor prior to disposal; and

(C) Caustic feed unloading, storage, and transfer equipment.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.16.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to **Commissioner's Order No. 2007-01** ~~326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)),~~ the Permittee shall not exceed the following PM_{10} emission limitations for the No. 4 UF process heaters:

~~Process Heater~~	~~PM_{10} Limit (lbs/MMBtu)~~	~~PM_{10} Limit (lbs/hour)~~
~~stack serving F-1, F-8A and F-8B~~	~~0.004~~	~~1.459~~
~~F-2~~	~~0.004~~	~~1.059~~
~~F-3~~	~~0.004~~	~~0.896~~
~~stack serving F-4R, F-5 and F-6~~	~~0.004~~	~~1.060~~
~~F-7~~	~~0.004~~	~~0.159~~

Process Heater	**PM_{10} Limit (lb/MMBTU)**	**PM_{10} Limit (lb/hour)**
Stack serving F-1, F-8A and F-8B	**0.0075**	**2.936**
F-2	**0.0075**	**2.131**
F-3	**0.0075**	**1.803**
Stack serving F-4, F-5 and F-6	**0.0075**	**2.124**
F-7	**0.0075**	**0.387**

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.16.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, the Permittee shall comply with the following SO_2 emission limitations for the No. 4 UF process heaters:

Process Heater Identification	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)
F-1	0.033	13.0 total
F-8A	0.033	
F-8B	0.033	
F-2	0.033	9.44
F-3	0.033	7.99
F-4R	0.033	9.41 total
F-5	0.033	
F-6	0.033	
F-7	0.033	1.72

D.16.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) For heaters F-1, F-8A, F-8B, F-2, F-3, F-4, F-5, F-6 and F-7, the emissions shall not exceed the following emissions limits:

Heater ID	NOx (lb/mmBTU)	CO (lb/mmBTU)	VOC(lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
F-1	0.098	0.082	0.0054	0.0019	0.0075
F-2	0.186	0.082	0.0054	0.0019	0.0075
F-3	0.275	0.082	0.0054	0.0019	0.0075
F-4R	0.275	0.082	0.0054	0.0019	0.0075
F-5	0.098	0.082	0.0054	0.0019	0.0075
F-6	0.098	0.082	0.0054	0.0019	0.0075
F-7	0.098	0.082	0.0054	0.0019	0.0075
F-8A	0.275	0.082	0.0054	0.0019	0.0075
F-8B	0.275	0.082	0.0054	0.0019	0.0075

(b) The Permittee shall comply with the following limits following the completion of the CXHO project:

Unit ID	Firing rate (10^3 mmBTU) per 12 month period	SO2 (tons per 12 consecutive month period)
F-1	259.30	1.4
F-8A	1,246.55	6.9
F-8B	1,246.55	6.9
F-2	1,488.32	8.2
F-3	1,576.80	8.7
F-4	847.97	4.7
F-5	427.49	2.4
F-6	190.09	1.1
F-7	317.11	1.8

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.16.~~3~~**4** Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements in Section E.2 for the F-1, F-8A, F-8B, F-2, F-3, F-4, F-5, F-6, and F-7 Process Heaters.

D.16.~~4~~**5** Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs)[326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(d) Prior to start-up of 4UF after the installation of the new reactor for the CXHO project, BP shall make a determination as to whether 40 CFR Part 60 GGGa has been triggered by the changes made as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered.

D.16.~~5~~**6** Requirements for 40 CFR Part 63, Subpart UUU

Pursuant to 40 CFR 63, Subpart UUU, the No. 4 Ultraformer Unit and associated bypass lines shall comply with the requirements of Section E.10.

D.16.~~6~~**7** Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC, and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual wastewater drains systems and oil-water separators subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

~~D.16.7 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements in Section E.20 for process heaters F-1, F-8A, F-8B, F-2, F-3, F-4R, F-5, F-6, and F-7, which comprise the affected source for the large gaseous fuel subcategory.~~

Compliance Determination Requirements

D.16.8 Operating Requirement

Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the F-1, F-8A, F-8B, F-2, F-3, F-4R, F-5, F-6, and F-7 Process Heaters.

D.16.9 Operating Requirement

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.16.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Compliance with the limits in D.16.3(a) shall be demonstrated as specified in Condition D.0.3.

D.16.10 Continuous Emissions Monitoring

The Total Reduced Sulfur continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A and F-8B in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements

D.16.~~10~~**11**Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.16.~~11~~**12**Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.16.2, and D.16.8, the Permittee shall maintain a daily record of the following for the F-1, F-8A, F-8B, F-2, F-3, F-4, F-5, F-6, and F-7 Process Heaters:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.16.1, the Permittee shall maintain records for the Process Heaters F-1, F-8A, F-8B, F-2, F-3, F-4, F-5, F-6 and F-7 as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.16.4** ~~D.16.3~~, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.16.5(a)** ~~D.16.4(a),~~ the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.16.5(b)** ~~D.16.4(b)~~, the Permittee shall keep records as specified in Section E.1 and E.4.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.16.7(a)** ~~D.16.6(a)~~, the Permittee shall keep records as specified in Sections E.1 and E.3.

(g) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.16.7(b)** ~~D.16.6(b)~~, the Permittee shall keep records as specified in Section E.6.

(h) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition **D.16.6** ~~D.16.5~~, the Permittee shall keep records as specified in Section E.10.

(i) In order to demonstrate compliance with Condition D.16.3, the Permittee shall maintain records of monthly firing rates and SO2 emissions at F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, and F-8B.

(j) Pursuant to 326 IAC 3-5- 6 and to document compliance with Condition D.16.10, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.16.~~12~~**13** Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.16.2, and D.16.8, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the F-1, F-8A, F-8B, F-2, F-3, F-4R, F-5, F-6, and F-7 Process Heaters.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.16.4** ~~D.16.3~~, the Permittee shall submit to IDEM, OAQ the reports specified in Condition E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.16.5(a)** ~~D.16.4(a)~~, the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.16.5(b)** ~~D.16.4(b)~~, the Permittee shall submit reports as specified in Sections E.1 and E.4.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.16.7(a)** ~~D.16.6(a)~~, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.16.7(b)** ~~D.16.6(b)~~, the Permittee shall submit reports as specified in Section E.6.

(g) Pursuant to 40 CFR 63, Subpart UUU and to demonstrate compliance with Condition **D.16.6** ~~D.16.5~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.10.

(h) In order to demonstrate compliance with Condition D.16.3, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions at heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, and F-8B to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(i) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.16.3 and D16.10, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.17 FACILITY OPERATION CONDITIONS - Hydrogen Unit

Facility Description [326 IAC 2-7-5(15)]:

(q) The Hydrogen Unit (HU), identified as Unit ID 698, commissioned in 1993, produces 99+% pure hydrogen needed for the refinery hydrotreating processes. The HU produces high purity hydrogen by reacting steam with methane. The reaction is carried out by heating the mixture in a furnace and reacting it in the presence of a catalyst. The HU includes the following sources of emissions and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) One (1) natural gas, refinery gas or liquified petroleum gas fired B-501 Process Heater rated at 366.3 MMBTU/hr, which exhausts at stack S/V 698-01. The Process Heater is equipped with low-NO_x burners.

(2) One (1) DDU Flare exhausting at stack S/V 698-02, burning natural gas as the pilot gas, used to control VOC emissions during emergency situations, unit startups and shutdowns and depressuring equipment for maintenance.

(3) Leaks from process equipment.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.17.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to **Commissioner's Order No. 2007-01** ~~326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)),~~ PM10 emissions from the B-501 HU Process Heater shall not exceed **0.0075 lb/MMBTU and 2.729 lb/hr** ~~0.009 lb/MMBTU and 3.340 lbs/hour~~.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.17.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from the B-501 process heater shall not exceed 0.033 lbs/MMBtu and 12.09 lbs/hour.

D.17.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

(a) The emissions from B-501 shall not exceed the following limits:

Heater ID	NOx (lb/mmBTU)	CO (lb/mmBTU)	VOC(lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
B-501	0.0675	0.02	0.0054	0.0019	0.0075

(b) After the start-up of the new Coker (#2 Coker), the SO2 emissions from B-501 shall not exceed 15.5 tons per 12 consecutive month period, with compliance determined at the end of each month.

(c) After the start-up of the new Coker (#2 Coker), the firing rate at B-501 shall not exceed 2,809,332 million BTU per 12 consecutive month period, with compliance determined at the end of each month.

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.17.~~3~~4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

(a) Pursuant to Permit CP 089-2055-00003, issued March 12, 1992 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements in Section E.2 for the HU Process Heater B-501and DDU Flare. The requirements for the DDU Flare are included in Section D.35.

(b) To demonstrate compliance with paragraph (a) of this condition and as approved by the U.S. EPA on March 3, 1999, the Permittee shall comply with the following alternative compliance monitoring requirements for the B-501 process heater:

(1) The Permittee shall sample the fuel gas at the representative location once every eight hour shift (three times per day) during the unit's operation with no more than ten hours elapsing between each sampling event. H_2S concentration shall be determined using three gas detection tubes with a span of 0-5 ppm for each sampling event.

(2) The Permittee shall calculate the average of the gas detection tube readings for each sampling event.

(3) If the H_2S concentrations equal or exceed 5 ppm within one hour, the Permittee shall begin performing H_2S sampling and analysis every hour using three gas tubes with a span of 0-200 ppm.

(4) When three consecutive hours of sampling with the 0-200 ppm gas detection tubes indicate that the H_2S concentration is below 5 ppm, the Permittee may revert to sampling as provided in paragraph (b)(1) of this condition.

(5) If the H_2S concentration ever exceeds 80 ppm, the Permittee shall install and certify a H_2S CEM within 180 days, and in the mean time continue to follow this approved alternative monitoring method.

(6) The Permittee shall submit quarterly summary reports indicating all instances when the H_2S concentration equals or exceeds 80 ppm, the actual H_2S concentration, and the times the unit was not operational.

(7) The Permittee shall maintain records of the gas detection tube results used to prepare the quarterly reports on file for at least two (2) years.

(8) The Permittee must obtain written approval from the U.S. EPA, Region V prior to using gas detection tubes with a 0-15 ppm span.

D.17.4**5** Emission Offset and Prevention of Significant Deterioration [326 IAC 2-2] [326 IAC 2-3]

Pursuant to Permit CP 089-2055-00003 issued on March 12, 1992, the Permittee shall comply with the following emission limitations and operating conditions:

~~(a) Nitrogen Oxide (NO_x) emissions from the B-501 Process Heater shall not exceed 0.078 lb/MMBTU. This is equivalent to NO_x emissions of 125 tons per year from the B-501 Process Heater.~~

(~~b~~ **a**) Carbon Monoxide (CO) emissions from the B-501 Process Heater shall not exceed 0.02 lb/MMBTU. ~~This is equivalent to CO emissions of 32 tons per year from the B-501 Process Heater.~~

(~~c~~) **(b)** All compressor seals in volatile organic compound (VOC) service shall be purged and vented to the flare header.

(~~d~~) **(c)** The Propane Dewaxing Unit and Asphalt Oxidizer Nos. 2 and 3 shall remain inoperative.

Compliance with these limits makes 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) and 326 IAC 2-3 (Emission Offset) not applicable.

D.17.~~5~~**6** Equipment Leaks of VOC and Hazardous Air Pollutants (HAPs)[326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGG] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.4, and E.13 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. Pursuant to 40 CFR 63.640(p), equipment that is subject to both 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC are required to comply only with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.17.~~6~~**7** Wastewater Requirements [326 IAC 12] [40 CFR 60, Subpart QQQ]

Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

~~D.17.7 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements specified in Section E.20 for process heater B-501, which comprise the affected source for the large gaseous fuel subcategory.~~

Compliance Determination Requirements

D.17.8 Operating Requirement

Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the B-501 Process Heater.

D.17.9 Operating Requirement

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.17.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Compliance with the limits in D.17.3(a) shall be demonstrated as specified in Condition D.0.3.

~~D.17.10 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]~~

~~(a) Within 36 months after the effective date of this permit, in order to demonstrate compliance with Condition D.17.3(a), the Permittee shall perform NO_x testing of the B-501 Process Heater. This test shall be repeated at least once every five (5) years from the date of the valid compliance demonstration.~~

~~(b) Within 36 months after the effective date of this permit, in order to demonstrate compliance with Condition D.17.4(b), the Permittee shall perform CO testing of the B-501 Process Heater. This test shall be repeated at least once every five (5) years from the date of the valid compliance demonstration.~~

~~(c) Testing shall be conducted in accordance with Section C.12 - Performance Testing utilizing methods approved by the Commissioner.~~

D.17.10 Continuous Emissions Monitoring

The Total Reduced Sulfur continuous emission monitoring system (CEMS) for B-501 shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limit for B-501 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.17.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.17.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.17.2, and D.17.8, the Permittee shall maintain a daily record of the following for the B-501 process heater:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.17.1, the Permittee shall maintain records for Process Heater B-501 as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.17.4** ~~D.17.3~~, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.17.6(a)** ~~D.17.5(a)~~, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Condition **D.17.6(b)** ~~D.17.5(b)~~, the Permittee shall keep records as specified in Sections E.1, E.4, and E.13.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.17.7** ~~D.17.6~~, the Permittee shall keep records as specified in Section E.6.

(g) In order to demonstrate compliance with Condition D.17.3, the Permittee shall maintain records of monthly firing rate and SO2 emissions at B-501.

(h) Pursuant to 326 IAC 3-5-6 and to demonstrate compliance with D.17.10, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.17.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.17.2, and D.17.8, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the B-501 process heater.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.17.4** ~~D.17.3~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.17.6(a)** ~~D.17.5(a)~~, the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Condition **D.17.6(b)** ~~D.17.5(b)~~, the Permittee shall submit reports as specified in Sections E.1, E.4, and E.13.

(e) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.17.7** ~~D.17.6~~, the Permittee shall submit reports as specified in Section E.6.

(f) In order to demonstrate compliance with Condition D.17.3, the Permittee shall submit a quarterly summary of the monthly firing rate and SO2 emissions at heater B-501 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(g) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.17.3 and D.17.10, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.18 FACILITY OPERATION CONDITIONS - Distillate Desulfurizer Unit

Facility Description [326 IAC 2-7-5(15)]:

(r) The Distillate Desulfurizer Unit (DDU), identified as Unit ID 700, commissioned in 1993, removes sulfur from petroleum distillates. Distillate feed is mixed with hydrogen, heated in process furnaces and passed over a catalyst bed to convert sulfur compounds to H_2S. The DDU includes the following emissions sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Process Heater WB-301, rated at 64.8 MMBTU/hr and exhausting to stack S/V 700-01. The Process Heater is equipped with low-NO_x burners and burns natural gas, refinery gas, or liquified petroleum gas.

(2) Process Heater WB-302, rated at 83.7 MMBTU/hr and exhausting to stack S/V 700-02. The Process Heater is equipped with low-NO_x burners and burns natural gas, refinery gas, or liquified petroleum gas.

(3) Leaks from process equipment.

(4) The Distillate Desulfurization Unit is connected to the DDU Flare System. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns and depressuring equipment for maintenance.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.18.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to **Commissioner's Order No. 2007-01** ~~326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)),~~ the Permittee shall not exceed the following PM10 emission limitations for the DDU Process Heaters:

~~Process Heater~~	~~PM10 Limit (lbs/MMBtu)~~	~~PM10 Limit (lbs/hour)~~
~~WB-301~~	~~0.004~~	~~0.250~~
~~WB-302~~	~~0.004~~	~~0.240~~

Process Heater	**PM10 Limit (lb/MMBTU)**	**PM10 Limit (lb/hour)**
WB-301	**0.0075**	**1.106**
WB-302	**0.0075**	

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.18.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from the WB-301 and WB-302 process heaters shall each not exceed 0.033 lbs/MMBtu and the total emissions from both process heaters shall not exceed 4.24 lbs/hour.

D.18.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

(a) For heaters WB-301 and WB-302, the emissions shall not exceed the following emissions limits:

Heater ID	NOx (lb/mmBTU)	CO (lb/mmBTU)	VOC (lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
WB-301	0.035	0.04	0.0054	0.0019	0.0075
WB-302	0.030	0.04	0.0054	0.0019	0.0075

(b) The Permittee shall comply with the following limits, following the start-up of the new Coker (#2 Coker):

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO2 tons per 12 consecutive month period
WB-301	620.21	3.4
WB-302	488.81	2.7

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.18.~~3~~**4** Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for WB-301; and WB-302 process heaters.

D.18.~~4~~**5** Emission Offset and Prevention of Significant Deterioration (PSD) [326 IAC 2-2] [326 IAC 2-3]

Pursuant to Permit CP 089-2055 -00003 issued on March 12, 1992, and amended on February 19, 1999, the Permittee shall comply with the following emission limitations and operating conditions:

~~(a)~~ Prior to start-up of the new coker (#2 Coker), nitrogen Oxide (NO_x) emissions from the WB-301 and WB-302 Process Heaters shall not exceed 0.065 lb/MMBTU. This is equivalent to total NO_x emissions of 36.6 tons per year from the WB-301 and WB-302 Process Heaters.

(b) Pursuant to permit CP 089-2055-0003, carbon Monoxide (CO) emissions from the WB-301 and WB-302 Process Heaters shall not exceed 0.04 lb/MMBTU. This is equivalent to total CO emissions of 22.5 tons per year from the WB-301 and WB-302 Process Heaters.

~~(c)~~ Prior to start-up of the new coker (#2 Coker), the input of natural gas and natural gas equivalents to Process Heaters WB-301 and WB-302 shall be limited to a total of 1089.7 million cubic feet (MMcf) per twelve (12) consecutive month period, with compliance determined at the end of every month. For the purpose of determining compliance with this limit, every one (1.0) MMcf of refinery gas usage shall be considered equivalent to one (1.0) MMcf of natural gas usage.

~~(d)~~ **(a)** All compressor seals in volatile organic compound (VOC) service shall be purged and vented to the flare header.

~~(e)~~ **(b)** The Propane Dewaxing Unit and Asphalt Oxidizer Nos. 2 and 3 shall remain inoperative.

Compliance with these limits makes 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) and 326 IAC 2-3 (Emission Offset) not applicable.

D.18.~~5~~**6** Equipment Leaks of VOC and Hazardous Air Pollutants (HAPs)[326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGG] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 12] [40 CFR 60, **Subpart GGGa]**

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.4, and E.13 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. Pursuant to 40 CFR 63.640(p), equipment that is subject to both 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC are required to comply only with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

(c) Prior to start-up of the new coker (#2 Coker), BP shall make a determination as to whether 40 CFR Part 60, Subpart GGGa has been triggered by component changes made on the DDU as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.18.~~6~~**7** Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

~~D.18.7 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements specified in Section E.20 for the process heaters WB-301 and WB-302, which comprise the affected source for the large gaseous fuel subcategory: process heaters WB-301 and WB-302.~~

Compliance Determination Requirements

D.18.8 Operating Requirement

Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the WB-301 and WB-302 Process Heaters.

D.18.9 Operating Requirement

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.18.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Compliance with limits in condition D.18.3(a) shall be demonstrated as specified in Condition D.0.3.

~~D.18.10 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]~~

~~(a) Within 36 months after the effective date of this permit, in order to demonstrate compliance with Condition D.18.4(a), the Permittee shall perform NO_x testing of the WB-301 Process Heater.~~

~~(b) Within 36 months after the effective date of this permit, in order to demonstrate compliance with Condition D.18.4(b), the Permittee shall perform CO testing of the WB-301 and WB-302 Process Heaters.~~

~~(c) Testing shall be conducted in accordance with Section C-12 - Performance Testing utilizing methods approved by the Commissioner.~~

D.18.10 Continuous Emissions Monitoring

The Total Reduced Sulfur continuous emission monitoring system (CEMS) for WB-301 and WB-302 shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for WB-301 and WB-302 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.18.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.18.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.18.2, and D.18.8, the Permittee shall maintain a daily record of the following for the WB-301 and WB-302 process heaters:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.8.1, the Permittee shall maintain records for the WB-301 and WB-302 as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.18.4** ~~D.18.3~~, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.18.6(a)** ~~D.18.5(a)~~, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC and to document compliance with Condition **D.18.6(b)** ~~D.18.5(b)~~, the Permittee shall keep records as specified in Sections E.1, E.4, and E.13.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.18.7(a)** ~~D.18.6(a)~~, the Permittee shall keep records as specified in Sections E.1 and E.3.

(g) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.18.7(b)** ~~D.18.6(b)~~, the Permittee shall keep records as specified in Section E.6.

(h) In order to demonstrate compliance with Condition D.18.3, the Permittee shall maintain records of monthly firing rates and SO2 emissions at WB-301 and WB-302.

(i) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.18.10, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.18.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.18.2, and D.18.8, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the WB-301 and WB-302 process heaters.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.18.4** ~~D.18.3~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.18.6(a)** ~~D.18.5(a)~~, the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC and to document compliance with Conditions **D.18.6(b)** ~~D.18.5(b)~~, the Permittee shall submit reports as specified in Sections E.1, E.4, and E.13.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.18.7(a)** ~~D.18.6(a)~~, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.18.7(b)** ~~D.18.6(b)~~, the Permittee shall submit reports as specified in Section E.6.

(g) In order to demonstrate compliance with Condition D.18.3, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions at heaters WB-301 and WB-302 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(h) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.18.3 and D.18.10, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.19 FACILITY OPERATION CONDITIONS - Cat Feed Hydrotreating Unit

Facility Description [326 IAC 2-7-5(15)]:

(s) The Cat Feed Hydrotreating Unit (CFHU), identified as Unit ID 171, built in 1982, removes sulfur from and improves the quality of gas oil feed to the Fluidized Cracking Units. The No. 4 Ultraformer Flare Stack, S/V 224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The CFHU is connected to the No. 4 Ultraformer flare stack. The flare is used to control VOC emissions, unit startups and shutdowns, and preparation of equipment for maintenance. The CFHU includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Three (3) process heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBTU/hr)	Stack Exhausted To	Emission Controls
F-801 A/B	66.5	171-01	low-NO_x burners
F-801C	60.0	171-02	ultra low-NO_x burners

(2) Leaks from process equipment.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.19.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to **Commissioner's Order No. 2007-01 the PM10 from the CFHU Process Heaters F-801A, F-801B and F-801C shall not exceed 0.0075 lb/MMBTU and 0.943 lb/hr (total).** ~~326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)), PM10 emissions from the CFHU Process Heaters F-801A/B shall be limited to 0.004 lbs/MMBtu and 0.246 lbs/hour.~~

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.19.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from the CFHU Process Heaters shall be limited as follows:

Process Heater Identification	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)
F-801A/B	0.035	2.33
F-801C	0.035	2.1

D.19.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

(a) For heaters F-801A, F-801B, and F-801C, the emissions shall not exceed the following emissions limits:

Heater ID	NOx (lb/mmBTU)	CO (lb/mmBTU)	VOC(lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
F-801A	0.049	0.082	0.0054	0.0019	0.0075
F-801B	0.049	0.082	0.0054	0.0019	0.0075
F-801C	0.036	0.0001	0.0054	0.0019	0.0075

(b) The Permittee shall comply with the following limits following the start-up of the new coker (#2 Coker):

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO2 tons per 12 consecutive month period
F-801A	215.5	1.2
F-801B	215.5	1.2
F-801C	215.5	1.2

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.19.~~3~~**4** Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SSM 089-14630-00003, issued on November 30, 2001 and 40 CFR 60.104(1)(a), the Permittee shall comply with the requirements specified in Section E.2 for the F-801 A/B and F-801C process heaters.

D.19.~~4~~**5** Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) 326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 12] [40 CFR 60, Subpart GGG]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.4, and E.13 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. Pursuant to 40 CFR 63.640(p), equipment that is subject to both 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC are required to comply only with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.19.~~5~~6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

~~D.19.6 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements specified in Section E.20 for the process heaters F-801A/B and F-801C, which comprise the affected source for the large gaseous fuel subcategory.~~

Compliance Determination Requirements

D.19.7 Operating Requirement

(a) Pursuant to Permit SSM 089-14630-00003, issued on November 30, 2001, fuel oil shall not be used as fuel for the CFHU Heaters.

(b) Compliance with the limits in Condition D.19.3(a) shall be demonstrated as specified in Condition D.0.3.

D.19.8 Prevention of Significant Deterioration (PSD) [326 IAC 2-2]

Pursuant to SSM 089-14630-00003, issued on November 30, 2001 and SPM 089-18588-00453, issued July 15, 2004, the Permittee shall comply with the following requirement:

Nitrogen oxide emissions from Furnace F- 801C shall be controlled by ultra low-NO_x burners having an emission rate of 0.040 pounds per million Btu or less. This limit equates to a potential to emit 10.51 tons of nitrogen oxides per year for Furnace F-801C. This condition renders the requirements of PSD as not applicable for nitrogen oxides.

~~D.19.9 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]~~

~~Within 5 years after the effective date of this permit, in order to demonstrate compliance with Condition D.19.11, the Permittee shall perform NO_x testing of the F-801C Process Heater utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five (5) years from the date of the valid compliance demonstration. Testing shall be conducted in accordance with Section C - Performance Testing.~~

D.19.9 Continuous Emissions Monitoring

The Total Reduced Sulfur continuous emission monitoring system (CEMS) for F-801A, F-801B, and F-801C shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for F-801A, F-801B, and F-801C in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

D.19.10 Operating Requirement

Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.19.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

Compliance Monitoring Requirements

D.19.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.19.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.19.2, and D.19.7, the Permittee shall maintain a daily record of the following for the CFHU Process Heaters F-801A/B and F-801C:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.19.1, the Permittee shall maintain records for the F-801A/B process heater as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.19.4** ~~D.19.3~~, the Permittee shall maintain the records specified in Section E.2.

~~(d)~~ Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.19.5(a)** ~~D.19.4(a)~~, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

~~(e)~~ Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Condition **D.19.5(b)** ~~D.19.4(b)~~, the Permittee shall keep records as specified in Sections E.1, E.4, and E.13.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, and to document compliance with Condition **D.19.6(a)** ~~D.19.5(a)~~, the Permittee shall keep records as specified in Sections E.1 and E.3.11.

(g) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.19.6(b)** ~~D.19.5(b)~~, the Permittee shall keep records as specified in Section E.6.

(h) In order to demonstrate compliance with Condition D.19.3, the Permittee shall maintain records of monthly firing rates at F-801A, F-801B, and F-801C, and monthly emissions of SO2 from F-801A, F-801B, and F-801C.

(i) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.19.9, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.19.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.19.2, and D.19.7, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the CFHU Process Heaters F-801A/B and F-801C.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Conditions **D.19.4** ~~D.19.3~~, the Permittee shall submit the records as specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.19.5(a)** ~~D.19.4(a)~~, the Permittee shall submit reports as specified in the LDAR plan.5

(d) Pursuant to 40 CFR 63, Subpart CC, 40 CFR 63, Subpart GGG, and to document compliance with Condition **D.19.5(b)** ~~D.19.4(b)~~, the Permittee shall submit reports as specified in Sections E.1, E.4, and E.13.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.19.6(a)** ~~D.19.5(a)~~, the Permittee shall submit records as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.19.6(b)** ~~D.19.5(b)~~, the Permittee shall submit records as specified in Section E.6.

(e) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.19.3 and D.19.10, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.20 FACILITY OPERATION CONDITIONS - Catalytic Refining Unit

Facility Description [326 IAC 2-7-5(15)]:

(t) The Catalytic Refining Unit (CRU), identified as Unit ID 201, which removes sulfur from petroleum naphthas and distillates. Naphtha or distillate feed is mixed with hydrogen, heated in process furnaces and passed over a catalyst bed inside one of two reactor trains, identified as D-114 and D-105, to convert sulfur compounds to hydrogen sulfide. Hydrogen sulfide is subsequently removed from the product by distillation followed by scrubbing with an amine. The CRU includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) Two (2) heaters, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Heater Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
F-101	72	201-01	Low-NO_x Burners
F-102A	60	201-02	Low-NO_x Burners

(2) The CRU is connected to the UIU flare stack, S/V 220-04. The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(3) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

Main Operating Scenario:
The CRU operates as a naphtha hydrotreater. Maximum production under this scenario is 27,000 barrels per day.

Alternative Operating Scenario:
The CRU operates as a distillate hydrotreater. Maximum production under this scenario is 40,000 barrels per day.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.20.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to ~~326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d))~~ **Commissioner's Order No. 2007-01**, the Permittee must comply with the following PM10 emission limitations for the CRU Process Heater~~s~~:

Process Heater	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
F-101	~~0.004~~ **0.0075**	~~0.267~~ **0.536**
F-102A	~~0.004~~ **0.0075**	~~0.290~~ **0.447**

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.20.2 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, the Permitted shall comply with the following SO_2 emission limitations for the CRU Process Heaters:

Process Heater Identification	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)
F-101	0.04	2.88
F-102A	0.04	2.40

D.20.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

(a) For heaters F-101 and F-102A, the emissions shall not exceed the following emissions limits:

Heater ID	NOx (lb/mmBTU)	CO (lb/mmBTU)	VOC(lb/mmBTU)	PM (lb/mmBTU)	PM-10 (lb/mmBTU)
F101	**0.08**	**0.082**	**0.0054**	**0.0019**	**0.0075**
F-102A	**0.08**	**0.082**	**0.0054**	**0.0019**	**0.0075**

(b) The Permittee shall comply with the following limits, following the completion of the CXHO project:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO2 tons per 12 consecutive month period
F-101	**208.49**	**1.2**
F-102A	**208.49**	**1.2**

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.20.~~3~~4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements in Section E.2 for the F-101 and F-102A process heaters.

D.20.~~4~~5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGG]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements in Sections E.1, E.4, and E.13 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. Pursuant to 40 CFR 63.640(p), equipment that is subject to both 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC are required to comply only with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.20.~~5~~6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil-water separators, and closed-vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

D.20.~~6~~7 Prevention of Significant Deterioration (PSD) [326 IAC 2-2]

Pursuant to SSM 089-15052-00453, issued November 17, 2003:

(a) Nitrogen Oxide emissions from Process Heater F-101 shall be controlled by low-NO_x burners having an emission rate of 0.080 pounds per million Btu heat input or less. ~~This limit equates to a potential to emit 25.2 tons of nitrogen oxides per year.~~

(b) Nitrogen Oxide emissions from Process Heater F-102A shall be controlled by low-NO_x burners having an emission rate of 0.080 pounds per million Btu heat input or less. ~~This limit equates to a potential to emit 21.0 tons of nitrogen oxides per year.~~

~~D.20. 7 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements in Section E.20 for the process heaters F-101 and F-102A, which comprise the affected source for the large gaseous fuel subcategory.~~

Compliance Determination Requirements

D.20.8 Operating Requirement

(a) Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the F-101 and F-102A Process Heaters.

(b) Compliance with the limits in Condition D.20.3(a) shall be demonstrated as specified in Condition D.0.3.

D.20.9 Continuous Emissions Monitoring

The Total Reduced Sulfur continuous emission monitoring system (CEMS) for F-101 and F-102A shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for F-101 and F-102 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

D.20.10 Operating Requirement

Pursuant to 326 IAC 7-4.1-3(b)(1) and except as specified in 326 IAC 7-4.1-2(d) and 326 IAC 7-2-1(c)(3), compliance with the sulfur dioxide emission limitations in Condition D.20.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

Compliance Monitoring Requirements

D.20.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.20.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions D.20.2, and D.20.8, the Permittee shall maintain a daily record of the following for the F-101 and F-102A Process Heaters:

(1) fuel type,

(2) average daily sulfur content for each fuel type,

(3) average daily fuel gravity for each fuel type,

(4) total daily fuel usage for each type, and

(5) heat content of each fuel.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.20.4** ~~D.20.3~~, the Permittee shall maintain the records as specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8, and to document compliance with Condition **D.20.5(a)** ~~D.20.4(a)~~, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.20.6** ~~D.20.5~~, the Permittee shall keep records as specified in Sections E.1 and E.3.

(e) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Condition **D.20.5(b)** ~~D.20.4(b)~~, the Permittee shall keep records as specified in Sections E.1, E.4., and E.13.

(f) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.20.1, the Permittee shall maintain records for the Process Heaters F-101 and F-102A, as specified in the Continuous Compliance Plan.

(g) In order to demonstrate compliance with Condition D.20.3, the Permittee shall maintain records of monthly firing rates and SO2 emissions at F-101 and F-102A.

(h) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.20.9, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.20.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.20.2 and D.20.8, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour, for the F-101 and F-102A Process Heaters.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.20.4** ~~D.20.3~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.20.5(a)** ~~D.20.4(a)~~, the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC, 40 CFR 63, Subpart GGG and to document compliance with Condition **D.20.5(b)** ~~D.20.4(b)~~, the Permittee shall submit reports as specified in Sections E.1 and E.4.

(e) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.20.7** ~~D.20.6~~, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(f) In order to demonstrate compliance with Condition D.20.3, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions at heaters F-101 and F-102A to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(g) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.20.3 and D20.9, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.21 FACILITY OPERATION CONDITIONS - Fluidized Catalytic Cracking Unit 500

Facility Description [326 IAC 2-7-5(15)]:

(u) The Fluidized Catalytic Cracking Unit (FCU) 500, constructed in 1945, identified as Unit ID 230 and rated at 115,000 barrels per day. This facility converts hydrocarbons that boil above 500°F into lower molecular weight products, which include gasoline and LPG. The cracking takes place as the gas oil and catalyst stream mix in the reactor. This process results in the catalyst being coated with coke, which is subsequently burned off in a regenerator. The FCU 500 includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) One (1) catalyst regenerator. Flue gas from the regenerator passes through an ammonia injection system, a waste heat recovery unit which generates steam, an Electrostatic Precipitator for particulate matter control, and is exhausted through stack S/V 230-01. The ammonia injection system includes aqueous ammonia injection and handling equipment. Aqueous ammonia is transferred from the FCU 600 SCR system's storage tanks.

(2) Three (3) catalyst storage bins, one each for spent, equilibrium, and fresh catalyst. Particulate emissions from the spent catalyst storage bin, identified as Bin F-52, are controlled by one (1) cyclone, which exhausts to stack S/V 230-03.

(3) One (1) flare exhaust at stack S/V 241-01 (VRU Flare). The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including two (2) compressors (identified as J-3D and J-3G), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system.

(5) As part of the FCU 500 WARP, per SSM 089-25484-00453, the existing FCU 500 blowdown stack is being shutdown and the pressure relief discharges that were vented to the blowdown stack will be routed to the VRU flare.

(6) The FCU 500 turnaround (TAR) project, per SSM 089- 25484-00453, for the repair or replacement of the power recovery turbine, and the air ring for the catalyst regenerator. The increases in emissions from FCU 500 TAR are already accounted for as CXHO project related emissions increases.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.21.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)), PM10 emissions from FCU 500 shall not exceed 1.22 pounds per thousand pounds of coke burned and 73.2 pounds per hour.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.21.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3 (formerly 326 IAC 7-4-1.1(c)), sulfur dioxide (SO_2) emissions from FCU 500 shall not exceed 750 pounds per hour.

~~D.21.3 State Operation Permit Requirements~~

~~Pursuant to Operation Permit 45-08-93-0561, issued on January 12, 1990 and amended on October 28, 1992, April 14, 1993 and October 29, 1993, the FCU 500 shall be limited as follows:~~

~~(a) particulate matter (PM) emissions shall not exceed 191.8 pounds per hour.~~

~~(b) SO_2 emissions shall not exceed 1500 pounds per hour.~~

D.21.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for FCU 500 after the start-up of the new Coker (#2 Coker):

(a) The emissions of NOx shall not exceed 155.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(b) The emissions of VOC shall not exceed 3.3 pounds per 1000 barrels of fresh feed used per 12 consecutive month period, with compliance determined at the end of each month.

(c) The emissions of SO2 shall not exceed 200.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) The emissions of PM and PM-10 shall not exceed 0.465 pounds per 1000 pounds of coke burned at FCU 500 per 12 consecutive month period, with compliance determined at the end of each month.

(e) The emissions of CO shall not exceed 147.2 tons per 12 consecutive month period, with compliance determined at the end of each month.

(f) The fresh feed used at FCU 500 shall not exceed 37.6 million barrels per 12 consecutive month period, with compliance determined at the end of each month.

(g) The coke burned at FCU 500 shall not exceed 669,191,000 pounds per 12 consecutive month period, with compliance determined at the end of each month.

(h) The FCU 500 blowdown stack shall be permanently shutdown and the pressure relief discharges that were routed to the blowdown stack will be routed to the VRU flare.

Compliance with the FCU 500 throughput limits and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, CO, SO2, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.21.4 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

Prior to start-up of the FCU 500 after the TAR project, BP shall make a determination as to whether 40 CFR 60, Subpart GGGa has been triggered by component changes made on the ARU as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.21.5 Requirements for 40 CFR Part 63, Subpart UUU

Pursuant to 40 CFR 63, Subpart UUU, Fluidized Catalytic Cracking Unit 500 shall comply with the requirements specified in Section E.10.

D.21.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, Subpart CC and 40 CFR 60, Subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.21.7 Alternative Opacity Requirements [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3(a), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed 20%; however, opacity levels shall not exceed 60% for any six (6) minute averaging period. Opacity in excess of 20% shall not continue for more than two (2) six (6) minute averaging periods in any twenty-four (24) hour period.

(b) Pursuant to 326 IAC 5-1-3(b), when moving ashes from the fuel bed or furnace in the FCU 500 boiler blowing tubes, opacity may exceed 20% in any one (1) six (6) minute averaging period. However, the opacity shall not exceed 60% for any six (6) minute averaging period and opacity in excess of 20% shall not continue for more than one (1) six (6) minute averaging period in a sixty (60) minute period. The averaging period shall not be permitted for more than three (3) six (6) minute averaging periods in a twelve (12) hour period.

Compliance Determination Requirements

D.21.8 Operating Requirement

(a) Pursuant to SPM 089-15202-00003, issued on April 24, 2002 and SPM 089-18588-00453, issued July 15, 2004, carbon monoxide (CO) emissions shall not exceed 500 parts per million by volume, on a dry basis, based on 1-hour averages. The CO limits shall not apply during periods of startup, shutdown, or malfunction.

(b) Compliance with the limits in Condition D.21.3(b) and (d) shall be demonstrated as specified in Condition D.0.3.

In order to demonstrate compliance with Condition D.21.3, after the startup of the New Coker (#2 Coker):

(c) The pressure relief discharges that were routed to the FCU 500 blowdown stack shall be routed to the VRU flare. The flare must be operated with a flame present at all times that FCU 500 is in operation.

D.21.9 Continuous Emissions Monitoring

The NOx, CO, and SO2 continuous emission monitoring systems (CEMS) for FCU 500 shall be calibrated, maintained, and operated for determining compliance with NOx, CO, and SO2 emissions limits for FCU 500 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements

D.21.~~9~~**10** Inspection and Monitoring Requirements for the Electrostatic Precipitator [326 IAC 6.8-8-7]

Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(r)(2)), the Permittee shall maintain a Continuous Compliance Plan (CCP) for the ESP. The CCP shall include recording, inspection, and maintenance procedures in accordance with the requirements provided in 326 IAC 6.8-8-7(2)(A) and (B) (formerly 326 IAC 6-1-10.1(r)(2)(A) and (B)), including operating parameters to be monitored and the inspection and maintenance schedule to be followed. The Permittee shall inspect the ESP according to the schedule and procedures specified in the CCP. Pursuant to 326 IAC 2-7-5(1)(B)(ii), the inspection schedule records shall be available for inspection by IDEM, OAQ for up to five (5) years after the date of inspection.

D.21.~~10~~**11** Continuous Monitoring [326 IAC 3-5-1(e)] [326 IAC 6.8-8]

(a) Pursuant to SPM 089-15202-00003, issued on April 24, 2002, SPM 089-18588-00453, issued July 15, 2004, and to demonstrate compliance with Conditions D.21.2 and D.21.7, continuous monitoring systems shall be installed, certified, calibrated, maintained, and operated in accordance with the applicable requirements of 40 CFR 60.13 and the CCP, and operated at all times when FCU 500 is in operation to monitor and record the following for the FCU 500 flue gas:

(1) The Permittee shall monitor and record the hourly average CO concentration, on a dry basis. Process analyzers, calibrated in accordance with the manufacturer's recommendations, may be used for this purpose.

(2) The Permittee shall use a NO_x CEMS to monitor performance of the FCU 500 during the life of the Consent Decree 2:96 CV 095 RL and to report compliance with the terms and conditions of the Consent Decree.

(3) The Permittee shall use an SO_2 CEMS to monitor performance of the FCU 500 and to report compliance with the terms and conditions of the Consent Decree 2:96 CV 095 RL.

(b) Pursuant to 326 IAC 3-5 and 326 IAC 6.8-8-5(2) (formerly 326 IAC 6-1-10.1(p)(2)), the Permittee shall continuously monitor the opacity of exhaust gases from the catalyst regenerator stack at all times when the catalyst regenerator is in operation. The Permittee shall comply with the performance and operating specifications in 326 IAC 3-5-2, the certification process in 326 IAC 3-5-3, the operation procedures in 326 IAC 3-5-4, and the quality assurance requirements in 326 IAC 3-5-5 for the continuous opacity monitor.

(c) Pursuant to 326 IAC 6.8-8-5(2) (formerly 326 IAC 6-1-10.1(p)(2)), the Permittee shall continuously monitor coke burn off rate, in pounds per hour, as specified in the Continuous Compliance Plan (CCP).

D.21.~~11~~**12**Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.21.~~12~~**13**Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(B) and to document compliance with Condition~~s~~ D.21.2 ~~and D.21.3(b),~~ the Permittee shall maintain daily records of the following:

(1) calculated coke burn off rate for FCU 500, and

(2) sulfur content of the coke.

(b) Pursuant to 326 IAC 3-5-6 and to document compliance with Conditions **D.21.3, D.21.7 , D.21.9 and D.21.11** ~~D.21.7 and D.21.10(b)~~, the Permittee shall keep the following records for the continuous opacity monitor and continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.21.4(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.21.4(b), the Permittee shall keep records as specified in Section E.1 and E.4.

(e) Pursuant to SPM 089-15202-00003, issued on April 24, 2002, and SPM 089-18588-00453, issued July 15, 2004, and to document compliance with Condition D.21.8, the Permittee shall maintain records of 1-hour average CO emissions.

(f) Pursuant to 326 IAC 6.8-8-3 and 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5), (q)(1), and (r)(2)) and to demonstrate compliance with Condition D.21.1, the Permittee shall maintain records for the FCU and ESP as specified in the Continuous Compliance Plan.

(g) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.21.6(a), the Permittee shall keep records as specified in Sections E.1 and E.3.

(h) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.21.6(b), the Permittee shall keep records as specified in Section E.6.

(i) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition D.21.5, the Permittee shall keep records as specified in Section E.10.

(j) In order to demonstrate compliance with Condition D.21.3, the Permittee shall maintain records of fresh feed usage at FCU 500 and the coke burned at FCU 500 each month.

(k) In order to demonstrate compliance with Condition D.21.3, the Permittee shall maintain records of monthly emissions of SO2, NOx, and CO from FCU 500.

D.21.~~13~~**14**Reporting Requirements

(a) Pursuant to 326 IAC IAC 7-4.1-3(b)(2) and to document compliance with Conditions D.21.2~~ and D.21.3(b)~~, the Permittee shall submit a report containing the average daily sulfur dioxide emission rate, in pounds per hour, for FCU 500 within thirty (30) days after the end of each calendar quarter.

(b) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions **D.21.7 and D.21.11** ~~D.21.7 and D.21.10(b)~~, the Permittee shall submit reports of excess opacity emissions within thirty (30) days of the end each of quarter in which excess emissions occur. Pursuant to 321 IAC 3-5-7, the reports shall include:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. The actual opacity of each averaging period for each period in excess of the opacity limit. If the exceedance occurs continuously beyond one (1) six (6) minute period, the Permittee shall report either the percent opacity for each six (6) minute period or the highest six (6) minute average opacity for the entire period.

(5) A summary itemizing the exceedances by cause.

(c) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the standard operating procedures (SOP) submitted to OAQ for the continuous opacity monitor, updates shall be submitted biennially.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.21.4(a), the Permittee shall submit reports as specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.21.4(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.

(f) To document compliance with Condition D.21.8 **and D.21.3**, the Permittee shall submit reports of excess ~~CO~~ emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission, in terms of 1-hr averages, and

(5) A summary itemizing the exceedances by cause.

(g) Pursuant to 40 CFR 63, Subpart UUU and to demonstrate compliance with Condition D.21.5, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.10.

(h) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.21.6(a), the Permittee shall subject reports as specified in Section E.1 and E.3.

(i) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.21.6(b), the Permittee shall submit reports as specified in Section E.6.

(j) In order to demonstrate compliance with Condition D.21.3, the Permittee shall submit quarterly reports for the fresh feed used and coke burned at FCU 500. The report submitted by the Permittee does require the certification by the "Responsible Official" as defined by 326 IAC 2-7-1(34).

(k) In order to demonstrate compliance with Condition D.21.3, the Permittee shall submit quarterly reports of monthly emissions of SO2, NOx, and CO from FCU 500. The report submitted by the Permittee does require the certification by the "Responsible Official" as defined by 326 IAC 2-7-1(34).

(I) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.21.3 and D.21.11, the Permittee shall submit reports of excess SO2, NOx, and CO emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.22 FACILITY OPERATION CONDITIONS - Fluidized Catalytic Cracking Unit 600

Facility Description [326 IAC 2-7-5(15)]:

(v) The Fluidized Catalytic Cracking Unit (FCU) 600, constructed in 1946, identified as Unit ID 240 and rated at 80,000 barrels per day. This facility converts hydrocarbons that boil above 500 ^{o}F into lower molecular weight products, which include gasoline and LPG. The cracking takes place as the gas oil and catalyst stream mix in the reactor. This process results in the catalyst being coated with coke, which is subsequently burned off in a regenerator**.** The FCU 600 includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) One (1) catalyst regenerator. Flue gas from the regenerator passes through a waste heat recovery unit, which generates steam and an Electrostatic Precipitator for particulate matter control. The flue gas is then directed to a selective catalytic reduction (SCR) system, which chemically reduces nitrogen oxide emissions by reaction with injected ammonia, and is exhausted through stack S/V 240-01.

(2) Two catalyst storage bins, one each for equilibrium and fresh catalyst. (Spent catalyst is stored in Bin F-52, which is associated with FCU 500.)

(3) One (1) flare exhausting at stack ID S/V 230-02 (FCU Flare). The flare is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including two (2) wet gas compressors (identified as J-3Dand J-3E), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and an instrumentation system.

(5) As part of the FCU 600 WARP, per SSM 089-25484-00453 the existing FCU 600 blowdown stack is being shutdown and the pressure relief discharges that were vented to the blowdown stack are being re-routed to the FCU flare.

(6) The FCU 600 turnaround (TAR) project, per SSM 089-25484-00453 , for the repair or replacement of the main fractionator overhead condensers, the slurry and pump around system, unit pump replacement, FCU flare tip replacement, and additional controls to reduce plugging on the SCR. The increases in emissions from FCU 600 TAR are already accounted for as CXHO project related emissions increases.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.22.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)), PM_{10} emissions from FCU 600 shall not exceed 1.10 pounds per thousand pounds of coke burned and 55.0 pounds per hour.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.22.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide (SO_2) emissions from FCU 600 shall not exceed 437.50 pounds per hour.

D.22.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for FCU 600:

After the startup of the New Coker (#2 Coker), the Permittee shall comply with the following:

(a) The emissions of NOx shall not exceed 49.7 tons per 12 consecutive month period, with compliance determined at the end of each month.

(b) The emissions of VOC shall not exceed 3.3 pounds per 1000 barrels of fresh feed used per 12 consecutive month period, with compliance determined at the end of each month.

(c) The emissions of SO2 shall not exceed 190.0 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) The emissions of PM and PM-10 shall not exceed 0.35 pounds per 1000 pounds of coke burned at FCU 600 per 12 consecutive month period, with compliance determined at the end of each month.

(e) The emissions of CO shall not exceed 92.1 tons per 12 consecutive month period, with compliance determined at the end of each month.

(f) The fresh feed used at FCU 600 shall not exceed 24.09 million barrels per 12 consecutive month period, with compliance determined at the end of each month.

(g) The coke burned at FCU 600 shall not exceed 428,802,000 pounds per 12 consecutive month period, with compliance determined at the end of each month.

(h) The FCU 600 blowdown stack shall be permanently shutdown and with the exhaust routed to the FCU stack.

Compliance with the FCU 600 throughput limits and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

Compliance Determination Requirements

~~D.22.3 State Operation Permit Requirements~~

~~Pursuant to Operation Permit 45-08-93-0562, issued on January 12, 1990 and amended on November 13, 1990 and April 14, 1993:~~

~~(a) particulate matter (PM) emissions shall not exceed 147.4 pounds per hour.~~

~~(b) SO_2 emissions shall not exceed 875 pounds per hour.~~

D.22.4 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 12] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Prior to start-up of the FCU 600 after the TAR project, BP shall make a determination as to whether 40 CFR 60, Subpart GGGa has been triggered by component changes made on the ARU as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.22.5 Requirements for 40 CFR Part 63, Subpart UUU

Pursuant to 40 CFR 63, Subpart UUU, the Fluidized Catalytic Cracking Unit 600 and associated bypass lines shall comply with the requirements of Section E.10.

D.22.6 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil-water separators, and closed-vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

D.22.7 Operating Requirement

Pursuant to SPM 089-15202-00003, issued on April 24, 2002 and SPM 089-18588-00453, issued July 15, 2004:

(a) The Permittee shall use a selective catalytic reduction (SCR) system to reduce Nitrogen Oxide (NO_x) emissions.

(b) The carbon monoxide (CO) emissions shall not exceed 500 parts per million by volume, on a dry basis, based on 1-hour averages. The CO limit shall not apply during periods of startup, shutdown, and malfunction.

(c) Compliance with limits in Condition D.22.3(b) and (d) shall be demonstrated as specified in Condition D.0.3.

In order to demonstrate compliance with Condition D.22.3, after the startup of the New Coker (#2 Coker):

(d) The pressure relief discharges that were routed to the FCU 600 blowdown stack shall be routed to the FCU flare. The flare must be operated with a flame present at all times that FCU 600 is in operation.

D.22.8 Alternative Opacity Requirements [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3(a), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed 20%; however, opacity levels shall not exceed 60% for any six (6) minute averaging period. Opacity in excess of 20% shall not continue for more than two (2) six (6) minute averaging periods in any twenty-four (24) hour period.

(b) Pursuant to 326 IAC 5-1-3(b), when moving ashes from the fuel bed or furnace in the FCU 500 boiler blowing tubes, opacity may exceed 20% in any one (1) six (6) minute averaging period. However, the opacity shall not exceed 60% for any six (6) minute averaging period and opacity in excess of 20% shall not continue for more than one (1) six (6) minute averaging period in a sixty (60) minute period. The averaging period shall not be permitted for more than three (3) six (6) minute averaging periods in a twelve (12) hour period.

D.22.9 Continuous Emissions Monitoring

The NOx, CO, and SO2 continuous emission monitoring systems (CEMS) for FCU 600 shall be calibrated, maintained, and operated for determining compliance with NOx, CO, and SO2 emissions limits for FCU 600 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements

D.22.~~9~~**10** Inspection and Monitoring Requirements for the Electrostatic Precipitator [326 IAC 6.8-8-7]

Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(r)(2)), the Permittee shall maintain a Continuous Compliance Plan (CCP) for the ESP. The CCP shall include recording, inspection, and maintenance procedures in accordance with the requirements provided in 326 IAC 6.8-8-7(2)(A) and (B) (formerly 326 IAC 6-1-10.1(r)(2)(A) and (B)), including operating parameters to be monitored and the inspection and maintenance schedule to be followed. The Permittee shall inspect the ESP according to the schedule and procedures specified in the CCP. Pursuant to 326 IAC 2-7-5(1)(B)(ii), the inspection schedule records shall be available for inspection by IDEM, OAQ for up to five (5) years after the date of inspection.

D.22.~~10~~**11** Continuous Monitoring [326 IAC 3-5][326 IAC 6.8-8]

(a) Pursuant to SPM 089-15202-00003, issued on April 24, 2002, SPM 089-18588-00453, issued July 15, 2004, and to demonstrate compliance with Condition D.22.~~7~~**9**(b), the Permittee shall:

(1) The Permittee shall use NOx CEMS to monitor performance of FCU 600 and to report compliance with the terms and compliance with the terms and conditions of Consent Decree 2:96 CV 095 RL.

(2) The Permittee shall measure and record the hourly average concentration, on a dry basis, of carbon monoxide in the exhaust gas stream. Process analyzers, calibrated in accordance with the manufacturer's recommendations, may be used for this purpose.

(3) The Permittee shall use a SO_2 CEMS to monitor performance of FCU 600 and to report compliance with the terms and conditions of Consent Decree 2:96 CV 095 RL.

(b) Pursuant to 326 IAC 3-5 and 326 IAC 6.8-8-5(2) (formerly 326 IAC 6-1-10.1(p)(2)), the Permittee shall continuously monitor the opacity of exhaust gases from the catalyst regenerator stack at all times when the catalyst regenerator is in operation. The Permittee shall comply with the performance and operating specifications in 326 IAC 3-5-2, the certification process in 326 IAC 3-5-3, the operation procedures in 326 IAC 3-5-4, and the quality assurance requirements in 326 IAC 3-5-5 for the continuous opacity monitor.

(c) Pursuant to 326 IAC 6.8-8-5(2) (formerly 326 IAC 6-1-10.1(p)(2)), the Permittee shall continuously monitor coke burn off rate, in pounds per hour, as specified in the Continuous Compliance Plan (CCP).

D.22.~~11~~**12** Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.22.~~12~~**13** Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(C) and to document compliance with Condition~~s~~ D.22.2 ~~and D.22.3(b)~~, the Permittee shall maintain daily records of the following:

(1) calculated coke burn off rate for FCU 600, and

(2) sulfur content of the coke.

(b) Pursuant to 326 IAC 3-5-6 and to demonstrate compliance with Conditions D.22.8, D.22.9 and D.22.~~10~~**11**, the Permittee shall keep the following records for the continuous opacity monitor and continuous emission monitors:

(1) One-minute block averages;

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities,

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.22.4(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.22.4(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(e) Pursuant to SPM 089-15202-00003, issued April 24, 2002, SPM 089-18588-00453, issued July 15, 2004, and to demonstrate compliance with Condition~~s~~ D.22.7 ~~and D.22.12~~, the Permittee shall maintain records of the 1-hour average CO emissions.

(f) Pursuant to 326 IAC 6.8-8-3 and 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5), (q)(1), and (r)(2)) and to document compliance with Condition D.22.1, the Permittee shall maintain records for the FCU and ESP as specified in the Continuous Compliance Plan.

~~(~~g) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.22.6, the Permittee shall keep records as specified in Sections E.1 and E.3.

(h) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition D.22.5, the Permittee shall maintain records as specified in Section E.10.

(i) In order to demonstrate compliance with Condition D.22.3, the Permittee shall maintain records of daily fresh feed to FCU 600 and the coke burned at FCU 600 each month.

(j) In order to demonstrate compliance with Condition D.22.3, the Permittee shall maintain records of monthly emissions of SO2, NOx, and CO from FCU 600.

D.22.**14**~~13~~ Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Condition~~s~~ D.22.2 ~~and D.22.3(b)~~, the Permittee shall submit a report containing the average daily sulfur dioxide emission rate in pounds per hour within thirty (30) days after the end of each calendar quarter.

(b) Pursuant to 326 IAC 3-5-7 and to document compliance with Condition D.22.~~10~~**11**(b), the Permittee shall submit reports of excess opacity emissions within thirty (30) days of the end of each quarter in which excess emissions occur. Pursuant to 321 IAC 3-5-7, the reports shall include:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. The actual opacity of each averaging period for each period in excess of the opacity limit. If the exceedance occurs continuously beyond one (1) six (6) minute period, the Permittee shall report either the percent opacity for each six (6) minute period or the highest six (6) minute average opacity for the entire period.

(5) A summary itemizing the exceedances by cause.

(c) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the standard operating procedures (SOP) submitted to OAQ for the continuous opacity monitor, updates shall be submitted biennially.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.22.5(a), the Permittee shall submit reports as specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.22.5(b), the Permittee shall submit reports as specified in Section E.4.

(f) **Pursuant to 326 IAC 3-5-7 and t**o document compliance with Conditions D.22.3 **and D.22.9**, the Permittee shall submit reports of excess CO, **SO2, and NOx** emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

(g) Pursuant to 40 CFR 63, Subpart UUU and to demonstrate compliance with Condition D.22.5, the Permittee shall submit to IDEM, OAQ the reports as specified in Section E.10.

(h) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.22.6, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(i) In order to demonstrate compliance with Condition D.22.3, the Permittee shall submit quarterly reports for the fresh feed used and coke burned at FCU 600 each month. The report submitted by the Permittee does require the certification by the "Responsible Official" as defined by 326 IAC 2-7-1(34).

(j) In order to demonstrate compliance with Condition D.22.3, the Permittee shall submit quarterly reports of monthly emissions of SO2, NOx, and CO from FCU 600. The report submitted by the Permittee does require the certification by the "Responsible Official" as defined by 326 IAC 2-7-1(34).

SECTION D.23 FACILITY OPERATION CONDITIONS - No. 1 Stanolind Power Station

Facility Description [326 IAC 2-7-5(15)]:

(w) A portion of No. 1 Stanolind Power Station (SPS) constructed in 1928 and identified as Unit ID 501. The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas, are NO_x budget units:

(1) The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Boiler Identification	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
~~#3 Boiler~~	~~265~~	~~501-01~~	~~None~~
~~#4 Boiler~~	~~265~~	~~501-01~~	~~None~~
#5 Boiler	265	501-02	None
#6 Boiler	265	501-02	None
#7 Boiler	265	501-02	None

Note: The boilers in No. 1 Stanolind Power Station are scheduled to be shut down as part of the CXHO project.

(2) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.23.1 **D.21.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits**

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the boilers ~~#3, 4~~, 5, 6, and 7 shall be permanently shutdown prior to the start-up of the new Coker (#2 Coker).

D.23.~~1~~ **2**Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

Until the shutdown of boilers #5, 6, and 7:

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1(d)), the Permittee shall comply with the following PM10 emission limitations for the No. 1 SPS Boilers:

Boiler	PM10 Limit (lbs/MMBtu)	PM10 Limit (lbs/hour)
~~Stack serving Boilers #3, and #4~~	~~0.016~~	~~15.809 (Total)~~
Stack serving Boilers #5, #6, and #7	0.016	13.244 (Total)

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), until shutdown of boilers,5, 6 and 7, the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.23.~~2~~ **3**Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Until the shutdown of boilers # 5, 6, and 7:

Pursuant to 326 IAC 7-4.1-3, the Permittee shall comply with the following SO_2 emission limitations for the No. 1 SPS Boilers:

Boiler	SO_2 Limit (lbs/MMBtu)	SO_2 Limit (lbs/hour)
~~#3~~	~~0.033~~	~~17.49 Total~~
~~#4~~	~~0.033~~	
#5	0.033	26.24 Total
#6	0.033	
#7	0.033	

D.23.~~3~~ **4**Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Until the shutdown of boilers # 5, 6, and 7:

Pursuant to SPM 089-15202-00003, issued April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the No. 1SPS Boilers.

D.23.4 **5**Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8]

Until the shutdown of boilers #, 5, 6, and 7:

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

D.23.~~5~~ **6**Nitrogen Oxides Budget Trading Program [326 IAC 10-4]

Until the shutdown of boilers #3, 4, 5, 6, and 7:

Pursuant to 326 IAC 10-4-1(a), the Permittee shall comply with Nitrogen Oxides Budget Trading program for boilers #3 through #7 which are specified in Section E.11.

D.23.~~6~~ **7**Wastewater/Waste Streams [40 CFR 60, Subpart QQQ] [326 IAC 12]

Until the shutdown of boilers # 5, 6, and 7:

Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual wastewater drains systems.

~~D.23.7National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements specified in Section E.20 for boilers #3, 4, 5, 6 and 7, which comprise the affected source for the large gaseous fuel subcategory.~~

Compliance Determination Requirements

D.23.8 Operating Requirement

Until the shutdown of boilers #5, 6, and 7:

Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003, fuel oil shall not be used as fuel for the No. 1SPS Boilers.

Compliance Monitoring Requirements

D.23.9 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Until the shutdown of boilers #5, 6, and 7:

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.23.10 Record Keeping Requirements

Until the shutdown of boilers #5, 6, and 7:

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions **D.23.3 and D.23.9** ~~D.23.2, and D.23.8~~, the Permittee shall maintain a daily record of the following for the No. 1SPS Boilers:

(1) operational status of each facility,

(2) fuel type,

(3) average daily sulfur content for each fuel type,

(4) average daily fuel gravity for each fuel type,

(5) total daily fuel usage for each type, and

(6) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(p) and 326 IAC 6-1-10.1(n)(5)) and to document compliance with Condition D.23.1(b), the Permittee shall maintain records for the Boilers #3, #4, #5, #6, and #7 as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.23.4(a)** ~~D.23.3(a)~~, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.23.5(a)** ~~D.23.4(a)~~, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.23.5(b)** ~~D.23.4(b)~~, the Permittee shall keep records as specified in Sections E.1 and E.4.

(f) Pursuant to 326 IAC 10-4 and to document compliance with Condition **D.23.6** ~~D.23.5~~, the Permittee shall keep records as specified in Section E.11.

(g) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.23.7** ~~D.23.6~~, the Permittee shall keep records as specified in Section E.6.

D.23.11 Reporting Requirements

Until the shutdown of boilers #5, 6, and 7:

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions **D.23.3 and D.23.9** ~~D.23.2 and D.23.8~~, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour for the No. 1 SPS Boilers.

(b) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.23.4** ~~D.23.3~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.23.5(a)** ~~D.23.4(a)~~, the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.23.5(b)** ~~D.23.4(b)~~, the Permittee shall submit reports as specified in Sections E.1 and E.4.

(e) Pursuant to 326 IAC 10-4 and to document compliance with Condition **D.23.6** ~~D.23.5~~, the Permittee shall submit reports as specified in Section E.11.

(f) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.23.7** ~~D.23.6~~, the Permittee shall submit reports as specified in Section E.6.

SECTION D.24 FACILITY OPERATION CONDITIONS - No. 3 Stanolind Power Station

Facility Description [326 IAC 2-7-5(15)]:

(x) A portion of No. 3 Stanolind Power Station (SPS) constructed as listed below and identified as Unit ID 503. The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas, are NO_x budget units:

(1) The following boilers, all of which burn refinery gas, natural gas, or liquified petroleum gas:

Boiler Identification	Installation Date	Maximum Heat Input Capacity (MMBtu/hr)	Stack Exhausted To	Emission Controls
#1 Boiler	1948	575	503-01	**(current)** low-NO_x burners, an induced flue gas recirculation (IFGR) system, and an over fired air (OFA) system
#2 Boiler	1948	575	503-02	**After CXHO: The low-NOx burners, IFGR and OFA will be replaced by conventional burners and a Selective Catalytic Reduction (SCR) system on Boilers # 1, 2, 3, 4, 6**
#3 Boiler	1951	575	503-03	
#4 Boiler	1951	575	503-04	
#6 Boiler	1953	575	503-05	

(2) Five (5) direct-fired duct burners, permitted in 2008, rated at 41 mmBTU/hr each, equipped with low NOx burners and controlled by a Selective Catalytic Reduction (SCR) system.

(~~2~~ **3**) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.24.1 Lake County PM10 Emission Limitations [326 IAC 6.8-2-6]

(a) Pursuant to 326 IAC 6.8-2-6 (formerly 326 IAC 6-1-10.1), PM10 emissions from each stack serving Boilers #1, #2, #3, #4 and #6 shall not exceed 0.030 pounds per million Btu heat input and 17.49 pounds per hour for each boiler.

(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.

D.24.2 Lake County PM10 Emissions Limitations [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2, PM emissions from the five (5) duct burners shall not exceed 0.03gr/dscf.

D.24.~~2~~**3** Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from Boilers #1, #2, #3, #4 and #6 shall each not exceed 18.98 pounds per hour and 0.033 pounds per million Btu heat input.

D.24.4 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for No. 3 Stanolind Power Station:

After the installation of the duct burners and the conventional burners and a Selective Catalytic Reduction (SCR) on boilers 1,2,3,4 and 6, the Permittee shall comply with the following for boilers 1, 2, 3, 4, and 6 at the stack vent:

(a) The emissions of NOx shall not exceed 0.02 pound per million BTU.

(b) The emissions of VOC shall not exceed 0.0054 pound per million BTU.

(c) The emissions of PM shall not exceed 0.0019 pound per million BTU.

(d) The firing rate (total) shall not exceed 24,303,535 mmBTU per 12 consecutive month period, with compliance determined at the end of each month.

(e) The firing rate (total) at the five (5) duct burners shall not exceed 1,732,947 mmBTU per 12 consecutive month period, with compliance determined at the end of each month.

(f) The emissions of CO (total) from boilers 1, 2, 3, 4, and 6 and the five (5) duct burners shall not exceed 260.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(g) The emissions of PM-10 from each boiler/SCR stack shall not exceed 0.0087 pound per million BTU.

Compliance with the limits on annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.24.~~3~~**5** Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to Permit SPM 089-15202-00003, issued April 24, 2002 and 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the No. 3SPS Boilers.

D.24.~~4~~**6** Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] **[326 IAC 12][40 CFR 60, Subpart GGGa]**

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may request the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements of Sections E.1 and E.2 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

Prior to start-up of the boilers 1, 2, 3, 4 and 6 after installation of the duct burners the conventional burners and a Selective Catalytic Reduction (SCR), BP shall make a determination as to whether 40 CFR 60, Subpart GGGa has been triggered by component changes made on the boilers as a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.24.~~5~~**7** Nitrogen Oxides Budget Trading Program [326 IAC 10-4]

Pursuant to 326 IAC 10-4-1(a), the Permittee shall comply with Nitrogen Oxides Budget Trading program for boilers #1 through #4 and #6, which are specified in Section E.11.

D.24.~~6~~**8** Wastewater/Waste Streams [326 IAC 12] [40 CFR 60, Subpart QQQ]

Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual wastewater drains systems.

~~D.24.7 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements specified in Section E.20 for boilers # 1, 2, 3, 4 and 6, which comprise the affected source for the large gaseous fuel subcategory.~~

Compliance Determination Requirements

D.24.~~8~~**9** Operating Requirement

(a) Pursuant to Permit SPM 089-15202-00003, issued on April 24, 2002, effective June 1, 2003 and SPM 089-18588-00453, issued July 15, 2004, fuel oil shall not be used as fuel for the No. 3SPS Boilers.

(b) Compliance with the limits in Condition D.24.4(a), (b) and (g) shall be demonstrated as specified in Condition D.0.3.

D.24.10 Continuous Emissions Monitoring

The CO analyzer for the boiler/duct burner stacks shall be calibrated, maintained, and operated for determining compliance with CO emissions limits for the boilers 1, 2, 3, 4, and 6 and the five (5) duct burners in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements

D.24.~~9~~**11** Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.24.~~10~~**12** Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document compliance with Conditions **D.24.3 and D.24.9** ~~D.24.2 and D.24.8,~~ the Permittee shall maintain a daily record of the following for the No. 3 SPS Boilers:

(1) operational status of each facility,

(2) fuel type,

(3) average daily sulfur content for each fuel type,

(4) average daily fuel gravity for each fuel type,

(5) total daily fuel usage for each type, and

(6) heat content of each fuel type.

(b) Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(p) and 326 IAC 6-1-10.1(n)(5)), and to document compliance with Condition D.24.1(b), the Permittee shall maintain records as specified in the Continuous Compliance Plan.

(c) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.24.6(a)** ~~D.24.4(a)~~, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) In order to demonstrate compliance with Condition D.24.3, the Permittee shall maintain records of monthly firing rates and CO emissions at No. 3 Stanolind Power Station boilers 1, 2, 3, 4, 6, and the five (5) duct burners.

D.24.~~11~~**13** Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document compliance with Conditions **D.24.3 and D.24.9** ~~D.24.2 and D.24.8~~, the Permittee shall submit a report to IDEM, OAQ within thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, in pounds per hour for the No. 3 SPS Boilers.

(b) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.24.6(a)** ~~D.24.4(a)~~, the Permittee shall submit reports as specified in the LDAR plan.

(c) In order to demonstrate compliance with Condition D.24.4, the Permittee shall submit a quarterly summary of the monthly firing rates and CO emissions the boilers 1, 2, 3, 4, 6 and five (5) duct burners to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(d) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.24.4, the Permittee shall submit reports of excess CO emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,

(2) Date of excess emissions,

(3) Time of commencement and completion for each excess emission,

(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.

(5) A summary itemizing the exceedances by cause.

(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(A) Date of downtime.

(B) Time of commencement.

(C) Duration of each downtime.

(D) Reasons for each downtime.

(E) Nature of system repairs and adjustments

SECTION D.25FACILITY OPERATION CONDITIONS - Hazardous Waste Treatment Facility ~~Fluid Bed Incinerator~~

Facility Description [326 IAC 2-7-5(15)]:

(y) **Hazardous Waste Treatment System:**

~~Fluid Bed Incinerator (FBI), identified as Unit ID 510, equipped with a wet venturi scrubber, wet electrostatic precipitator (WESP) and a carbon bed absorber. This is a refinery pollution control system for hazardous waste materials and regulated under the Resource Conservation and Recovery Act (RCRA) and the Hazardous Waste Combustion MACT Standards. It is designed to treat API separator sludge, DAF skimmings and biological solids from the waste water treatment plant. The WESP and carbon bed absorber were installed in 2003. This facility includes the following emission sources and may also include insignificant activities listed in Section A.4 of this permit:~~

~~(1) The following incinerator fired by No.2 fuel oil:~~

~~Incinerator~~	~~Construction Date~~	~~Maximum Heat Release Capacity~~	~~Stack Exhausted to~~	~~Control Devices~~
~~FBI~~	~~1972~~	~~82 MMBtu/hr~~	~~510-01~~	~~Wet venturi scrubber with demisting vanes for PM control~~ ~~Wet Electrostatic Precipitator~~ ~~Carbon Bed Absorber~~

Dewatering and thermal desorption system for processing sludge, to be installed as part of CXHO project, including dissolved air flotation skimmimgs (DAF) and API oil/water separator sludge. The dewatering system will be equipped with a wet scrubber and carbon canister system and the thermal desorption unit will be equipped with a vapor recovery system to optimize absorption of hydrocarbons The feed rate capacities at the dewatering system and thermal desorption systems are 22,500 tons of feed per year and 9,000 dry tons of solids per year, per year, respectively. This facility includes the following emission sources and may include insignificant activities listed in Section A.4 of the permit:

(1) Two (2) centrifuges;

(2) Two (2) sludge surge tanks;

(3) One (1) oil/water mixture surge tank;

(4) One (1) enclosed auger transfer system;

(5) One (1) vapor recovery system on the thermal desorption unit including: an oil condensing/scrubbing system, a water condensing/scrubbing system, and an oil water separator. Uncondensed vapors from this system are routed to the two (2) diesel fired burners for destruction of VOCs.

Insignificant Activities:

(6) Two (2) diesel fired burners rated at 4 mmBTU/hr each, to supply heat to the thermal desorption system.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.25.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from each of the two (2) diesel fired burners shall not exceed 0.03 grains per dry standard cubic foot.

D.25.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for the dewatering and thermal desorption system:

The VOC emissions from the thermal desorption, thermal dewatering system and associated fugitives shall not exceed 2.4 tons per 12 consecutive month period, with compliance at the end of each month.

Compliance with the VOC emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

Compliance Determination Requirements

D.25.3 Petroleum Refineries [326 IAC 8-4-2]

Pursuant to 326 IAC 8-4-2(2), the Permittee shall equip all wastewater (oil/water) separators, forebay, and openings in covers with lids or seals such that the lids or seals are in the closed position at all times except when in actual use.

D.25.4 Wastewater / Waste Streams [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for all wastewater tanks and waste streams associated with the dewatering and thermal desorption system, individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, subpart CC specified in Section D.1.

D.25.5 Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil-water separators, and closed-vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

D.25.6 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 12] **[40 CFR 60, Subpart GGGa]**

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may request the Permittee to revise the plan.

(d) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements of Sections E.1 and E.2 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.25.7 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for the two (2) thermal desorption burners.

Compliance Monitoring Requirements

D.25.8 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.25.9 Record Keeping Requirements

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall keep records as specified in Section E.1 and E.3.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall keep records as specified in Section E.6.

(c) Pursuant to 40 CFR 60, Subpart J, the Permittee shall keep records as specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.25.6, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

D.25.10 Reporting Requirements

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall submit reports as specified in Section E.6.

(c) Pursuant to 40 CFR 60, Subpart J, the Permittee shall submit reports as specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.25.6, the Permittee shall submit reports as specified in the LDAR plan.

~~D.25.1 Lake County PM10 Emission Limitations [326 IAC 6.8-1-6]~~

~~(a) Pursuant to 326 IAC 6.8-1-6 (formerly 326 IAC 6-1-10.1(d)), PM10 emissions from the FBI shall not exceed 6.84 lbs per hour and 0.173 lbs per ton based on 79,000 lbs per hour fluidizing air flow.~~

~~(b) Pursuant to 326 IAC 6.8-8 (formerly 326 IAC 6-1-10.1(l)(3)), the Permittee shall operate the emission units listed in paragraph (a) of this condition in accordance with the Continuous Compliance Plan (CCP). Pursuant to 326 IAC 6.8-8-8(c) (formerly 326 IAC 6-10.1-1(u)), the Permittee shall update the CCP as needed, retain a copy of any changes and updates to the CCP onsite, and make the revised CCP available for inspection by IDEM, OAQ. The Permittee shall submit the revised CCP to IDEM, OAQ, within thirty (30) days of the update. If IDEM, OAQ determines that the procedures specified in the plan will not demonstrate compliance with 326 IAC 6.8-8, IDEM, OAQ may require the Permittee to revise the plan.~~

~~D.25.2 Sulfur Dioxide (SO_2) [326 IAC 7-4.1-3]~~

~~Pursuant to 326 IAC 7-4.1-3, sulfur dioxide emissions from the FBI shall not exceed 1.78 pounds per hour.~~

~~D.25.3 Mercury (Hg) Limitations [326 IAC 14-1] [40 CFR 61, Subpart E]~~

~~(a) Pursuant to 40 CFR 61, Subpart E, the Permittee shall comply with the requirements specified in Section E.18 for the FBI, except as specified in paragraph (b) of this condition.~~

~~(b) As allowed under the waiver approved by the U.S. EPA on May 11, 2006, the Permittee may demonstrate compliance with the performance testing requirements of 40 CFR 61.53 using performance tests for mercury required by 40 CFR 63, Subpart EEE, which are incorporated in Section E.19.~~

~~D.25.4 Standards for Hazardous Air Pollutants from Hazardous Waste Combustion [326 IAC 20-28] [40 CFR 63, Subpart EEE]~~

~~Pursuant to 40 CFR 63, Subpart EEE, the Permittee shall comply with the requirements specified in Section E.19 for the Fluid Bed Incinerator (FBI).~~

~~**Compliance Determination Requirements**~~

~~D.25.5 Testing [326 IAC 2-7-6(1), (6)] [326 IAC 2-1.1-1]~~

~~(a) Within 36 months after the effective date of this permit and in order to demonstrate compliance with Condition D.25.2, the Permittee shall perform SO_2 testing for the FBI utilizing methods as approved by the Commissioner.~~

~~(b) These tests shall be repeated at least once every five (5) years from the date of the valid compliance demonstration. Testing shall be conducted in accordance with Section C – Performance Testing.~~

~~D.25.6 Inspection of Scrubber [326 IAC 6.8-8-7(3)]~~

~~Pursuant to 326 IAC 6.8-8-7(3) (formerly 326 IAC 6-1-10.1(r)(2)(B)), the Permittee shall inspect the ESP according to the schedule and procedures specified in the Continuous Compliance Plan.~~

~~Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]~~

~~D.25.7 Monitoring of Scrubber [326 IAC 6.8-8-7(r)]~~

~~Pursuant to 326 IAC 6.8-8-7(2) (formerly 326 IAC 6-1-10.1(r)(2)(A)), the Permittee shall monitor operating parameters of the scrubber according to the procedure specified in the Continuous Compliance Plan.~~

~~Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]~~

~~D.25.8 Record Keeping Requirements~~

~~Pursuant to 326 IAC 6.8-8-7 (formerly 326 IAC 6-1-10.1(n)(5)), the Permittee shall maintain records for the FBI scrubber as specified in the Continuous Compliance Plan.~~

SECTION D.26 FACILITY OPERATION CONDITIONS - Wastewater Treatment Plant

Facility Description [326 IAC 2-7-5(15)]

(z) Wastewater Treatment Plant (WWTP), identified as Unit ID 544. This facility treats the water used in the refining process that comes into contact with oil or chemicals. In the first step, the heavier solids are removed at the inlet to the WWTP and the floating oil is skimmed from the surface of the wastewater in the API separator boxes. The oil is then recycled back to the refinery. The water is then aerated in the Air Flotation Unit where additional solid impurities are floated and skimmed. Thereafter, it moves to the Activated Sludge Plant where special bacteria digest the remaining contaminants. The water then passes through a clarifier and then eight (8) final filters before being returned to Lake Michigan. This facility includes the following emission sources and may ~~also~~ include insignificant activities listed in section A.4 of this permit:

(1) The following units are equipped with closed vent systems: oil sump P-1, oil sump P-2, and Diffused Air Floatation (DAF) Secondary Boxes, which vent to a biofilter and carbon canisters; Tank 569 is equipped with a conservation vent.

(2) The following units are equipped with a fixed-roof or floating roof: Interceptor Box, Diversion Box (from Tank 5051 to DAF), DAF Flash Mixer, DAF Influent Channel, DAF Effluent Channel, DAF Primary Boxes, and DAF Sump.

(3) One (1) storage tank (identified as Tank 5051) having a maximum storage capacity of 10,000,000 gallons, constructed in 1988 and equipped with an external floating roof.

(4) One (1) storage tank (identified as Tank 5050) having a maximum storage capacity of 10,000,000 gallons, constructed in 1988. This tank is used for storm event and upset impoundments.

(5) Seven (7) oil-water/solids separator units enclosed with a fixed-roof: Bar Screen, #7 API Separator Fixed Cover, #7 API Separator Primary Inlet, #7 API Separator Secondary Inlet, #7 API Separator Secondary Outlet, #7 API Separator Inlet Channel Section, and #7 API Separator Gear Boxes.

(6) One (1) storage tank (identified as Tank 5052) having a maximum storage capacity of 11,676,000 gallons, constructed as part of the CXHO Project. This tank is used as a stormwater equalization tank and is equipped with an external floating roof.

(7) A brine treatment system with seven (7) wastewater tanks with vertical fixed roofs, constructed as part of CXHO project, identified as:

(A) TK-105A, with a storage capacity of 867,180 gallons;
(B) TK-105B, with a storage capacity of 867,180 gallons;
(C) TK-101, with a storage capacity of 66,096 gallons;
(D) TK-102, with a storage capacity of 66,096 gallons;
(E) TK-103, with a storage capacity of 66,096 gallons;
(F) TK-104A, with a storage capacity of 89,943 gallons; and
(G) TK-104B, with a storage capacity of 89,943 gallons.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.26.1 Petroleum Refineries [326 IAC 8-4-2]

Pursuant to 326 IAC 8-4-2 (2), the Permittee shall equip all wastewater (oil/water) separators, forebay, and openings in covers with lids or seals such that the lids or seals are in the closed position at all times except when in actual use.

D.26.2 Wastewater / Waste Streams [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for tank 5051, individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, subpart CC specified in Section D.1.

(d) Pursuant to 40 CFR 63.647 of 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements of 40 CFR 61, Subpart FF, specified in Section E.3, for stormwater equalization tank 5052.

(e) Pursuant to 40 CFR 63.647 of 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements of 40 CFR 61, Subpart FF, specified in Section E.3, for the seven (7) storage tanks in the brine treatment facility.

D.26.3 Volatile Organic Compound (VOC) Emission Offset

Pursuant to OP 45-08-93-0574, issued January 12, 1990, the VOC emissions from the Oil-Water Separator (#7) shall not exceed 602 tons per year.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.26.4 Record Keeping Requirements

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.26.2(a), the Permittee shall keep records as specified in Section E.1 and E.3.

(b) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.26.2(b), the Permittee shall keep records as specified in Section E.6.

D.26.5 Reporting Requirements

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.26.2(a), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(b) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.26.2(b), the Permittee shall keep records as specified in Section E.6.

SECTION D.27 FACILITY OPERATION CONDITIONS - Oil Movements

Facility Description [326 IAC 2-7-5(15)]

(aa) Oil Movements, identified as Unit 640. This facility is used to store, blend, and ship products. Gasoline blending components are custom blended into various grades of gasoline. Additive and other compounds are blended into the products to give them their unique characteristics. Furnace oil and other distillates are also blended using components from process units or storage. Crude oil and feedstocks for process units and products are also stored at this location. Product loading operations include the pipeline and railcar racks. This facility includes the following emission sources and may ~~also~~ include insignificant activities listed in section A.4 of this permit:

(1) One (1) internal floating roof storage tank identified as 3730, storing ethanol, constructed in 1955, with a maximum storage capacity of 1,050,721 gallons.

(2) Ten (10) external floating roof storage tanks storing petroleum hydrocarbon with vapor pressure less than 15 psia, comprising the following tanks:

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3529	1948	858,000
3637	1956 **permitted in 2008 for reconstruction (SPM 089-25488-00453)**	6,353,000
3901	1956	1,906,000
3902	1956	1,906,000
3915	1980	6,353,460
3916	1980	13,666,998
3917	1980	25,413,839
3918	1980	13,666,998
3919	1980	13,666,998
3920	1980	13,666,998

(3) Sixty-seven (67) internal floating roof storage tanks, storing petroleum hydrocarbon with vapor pressure less than 15 psia, comprising the following tanks:

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3474	1992	3,734,422
3475	1994	3,865,445
3476	1984	3,085,016
3477	1971	4,066,214
3480	1982	4,026,505
3482	1972	169,426
3483	1924	3,382,264
3484	1996	3,865,445
3486	1979	4,026,505
3487	1980	4,026,505
3488	1994	3,865,445
3489	1996	3,865,445
3492	1925/1971	3,382,000
3493	1995	3,865,445
3510	1949	4,235,640
3511	1973	4,066,214
3512	1958	4,066,214
3513	1971	4,066,214
3514	1984	4,066,214
3525	1981	4,026,505

3526	1943/1979	4,026,505
3527	1991	3,382,264
3528	1993	3,865,445
3531	1948/1997	857,717
3532	1953	868,306
3533	1953	4,235,640
3534	1955/1973	71,000
3549	1993	588,283
3553	1981	5,070,343
3554	1981	5,070,343
3558	1972/1986	376,501
3600	1993	847,128
3601	1977	3,702,020
3602	1979	3,856,271
3604	1980	3,856,271
3605	1977	3,702,000
3622	1993	3,865,445
3624	1932	3,382,264
3629	1992	3,865,445
3631	1944	3,382,000
3633	1950	5,282,000
3635	1954	5,070,000
3639	1956	6,353,460
3641	1956	6,353,460
3701	1943/1993	3,382,264
3702	1943/1982/1997	3,382,264
3703	1944/1982 **(replaced in 2006)**	3,382,264
3704	1944/1980	3,382,264
3705	1944	3,382,264
3706	1944	3,382,264
3707	1944	3,382,264
3708	1943	853,895
3709	1943	825,434
3710	1943	2,059,000
3715	1945/1987/1998	3,382,264
3716	1996	3,865,445
3727	1948	857,717
3728	1970	857,717
3860	1993	211,782
3900	1956/2005	1,906,000
3904	1956/1986	3,388,512
3905	1956	6,353,460
3907	1956/1996	3,388,512
3909	1956	3,388,512
3911	1956/1986	3,388,512
3912	1956	6,353,460
3914	1956	3,388,512

(4) Miscellaneous Storage tanks including the following:

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity	Vapor Pressure of Liquid (psia)
D-424	4ULTRAFORMER	Methanol Tank	--	3,744	<0.5
F-011	4B TREATER	Casper Dewaterer	1949	17,624	<0.5

TK-0563	INCINERATOR	Aux. Fuel Oil	1971	49,378	<0.5
TK-3228	CRUDE STA	Decanted Oil	1948	596,570	<0.5
TK-3234	CRUDE STA	Decanted Oil	1940	858,298	<0.5
TK-3464	BERRY LAKE	Decanted Oil	1957	2,705,472	<0.5
TK-3465	BERRY LAKE	Plant Fuel	1973	3,413,088	<0.5
TK-3468	BERRY LAKE	TGO	1958	3,381,840	<0.5
TK-3491	SO. TK FLD.	Lsho	1992	3,876,768	<0.5
TK-3496	SO. TK FLD.	Distillate	1992	3,876,768	<0.5
TK-3498	SO. TK FLD.	Amoco Premier Diesel [Future Lsfo]	1929	3,373,413	<0.5
TK-3499	SO. TK FLD.	Amoco Premier Diesel [Future Lsfo]	1996	3,870,720	<0.5
TK-3500	SO. TK FLD.	Furnace Oil [Future Hmd]	1996	3,870,720	<0.5
TK-3505	SO. ANNEX	Heater Oil	1949	4,254,768	<0.5
TK-3509	SO. TK FLD.	Furnace Oil	1948	3,381,840	<0.5
TK-3546	SO. TK FLD.	Bronze Dye	1962	16,800	<0.5
TK-3547	SO. TK FLD.	Purple Dye	1962	16,800	<0.5
TK-3548	SO. TK FLD.	Isonox 133	1962	16,800	<0.5
TK3567	--	--	--	17,000	<0.5
TK-3569	MARINE DOCK	DCO	1981	4,796,064	<0.5
TK-3571	MARINE DOCK	HS Resid/Black Oil	1971	5,539,968	>0.5 and <0.75
TK-3572	MARINE DOCK	HS Resid/Black Oil	1971	5,539,968	>0.5 and <0.75
TK-3606	STIGLITZ PK.	Amoco Jet Fuel A [New 1996]	1996	3,701,376	<0.5
TK-3607	STIGLITZ PK.	Amoco Jet Fuel A	1993	3,729,600	<0.5
TK-3609	STIGLITZ PK.	HS Resid	1973	9,652,608	<0.5
TK-3610	STIGLITZ PK.	HS Resid	1973	9,652,608	<0.5
TK-3611	STIGLITZ PK.	HS Resid	1973	8,513,400	<0.5
TK-3613	STIGLITZ PK.	HS Resid	1992	3,876,768	<0.5
TK-3711	IND. TK FLD.	Lcco	1993	2,818,368	<0.5
TK-3712	IND. TK FLD.	Lcco	1945	3,357,600	<0.5
TK-3714	IND. TK FLD.	Distillate/Gas Oil	1999	3,852,576	<0.5
TK-3717	IND. TK FLD.	Fcu Feed Mixed	1943	3,263,190	<0.5
TK-3718	IND. TK FLD.	Gas Oil	1996	3,871,379	<0.5
TK-3719	IND. TK FLD.	Gas Oil	1943	3,357,600	<0.5
TK-3720	IND. TK FLD.	Gas Oil	1946	3,357,600	<0.5
TK-3721	IND. TK FLD.	Gas Oil	1946	3,357,600	<0.5
TK-3722	IND. TK FLD.	Gas Oil	1952	4,227,300	<0.5
TK-3723	IND. TK FLD.	Gas Oil	1954	3,386,880	<0.5
TK-3726	IND. TK FLD.	Amoco Jet Fuel A	1948	857,356	<0.5
TK-3733	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,383,520	<0.5
TK-3734	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,383,520	>0.5 and <0.75
TK-3735	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,411,072	<0.5
TK-3867	SO. TK FLD.	Stadis 450	1967	17,640	<0.5
TK-3868	SO. TK FLD.	Amogard	1953	17,640	>0.5 and <0.75
TK-3869	SO. TK FLD.	Pour Depressant	1956	23,436	<0.5
TK-3872	CRUDE STA	Used Motor Oil	1985	15,120	<0.5
TK-3876	South TF	Cetane Improver	1993	14,381	<0.5
TK-3906	J&L TK FLD.	Lsfo	1956	3,381,840	>0.5 and <0.75
TK-3908	J&L TK FLD.	Amoco Premier Diesel	1956	3,381,840	<0.5
TK-3910	J&L TK FLD.	Furnace Oil [Hs]	1956	3,381,840	<0.5
TK-3913	J&L TK FLD.	Furnace Oil [Ls]	1956	3,402,977	<0.5
TK-6078	ASPHALT	HS Resid/Black Oil	1948	1,931,000	<0.5
TK-6113	ASPHALT	Paving Base	1944	810,600	<0.5
TK-6114	ASPHALT	Paving Base	1944	810,600	<0.5

TK-6125		Paving Base	1998	3108932	<0.5
TK-6126		Paving Base	1999	3,108,000	<0.5
TK-6127		Paving Base	2000	3,108,000	<0.5
TK-6128		Paving Base	1971	3,225,600	<0.5
TK-6129		Paving Base	2005	3,108,000	<0.5
TK-6148		Paving Base	1948	3,108,000	<0.5
TK-6149		Paving Base	1948	3,108,000	<0.5
TK-6150		HS Resid	1986	810,600	<0.5
TK-6153		HS Resid	1979	1,386,000	<0.5
TK-6248	ASPHALT	Low Sul Resid	1973	7,218,928	<0.5
TK-6249	ASPHALT	Low Sul Resid	1973	7,218,928	<0.5
TK-6250	ASPHALT	HS Resid	1971	7,218,928	<0.5
TK-6251	ASPHALT	Paving Base	1971	7,218,928	<0.5
TK-6252	ASPHALT	HS Resid	1972	7,215,268	<0.5
TK-6253	ASPHALT	Paving Base	1971	7,218,928	<0.5
TK-6261	ASPHALT	HS Resid	1973	451,183	<0.5
TK-6262	ASPHALT	HS Resid	1972	451,183	<0.5
~~BT-002~~	~~MARINE DOCK~~	~~Out of Service~~	~~1968~~	~~874,944~~	~~--~~
TK-0559	ASU	Out of Service	1989	146,869	--
TK-0560	ASU	Out of Service	1948	587,477	--
TK-0568		Out of Service	Before 1973	--	--
TK-3167		Out of Service	1926	3,361,114	--
TK-3168		Out of Service	1926	1,931,170	--
TK-3169		Out of Service	1926	3,361,114	--
TK-3232	CRUDE STA	Out of Service	1940	857,356	--
TK-3259	CRUDE STA	Out of Service	1951	846,720	--
TK-3260	CRUDE STA	Out of Service	1930	375,986	--
TK-3279	MARINE DOCK	Out of Service	1951	85,302	--
TK-3309	CRUDE STA	Out of Service	NA	7,050	--
TK-3373		Out of Service	--	--	--
TK-3471	SO. TK FLD.	Out of Service	1973	7,050	--
TK-3485	SO. TK FLD.	Out of Service	1924	3,373,413	--
TK-3494	SO. TK FLD.	Out of Service	1926	3,373,413	--
TK-3497	SO. TK FLD.	Out of Service	1926	3,373,413	--
TK-3506	SO. ANNEX	Out of Service	1936	3,373,413	--
TK-3507	SO. ANNEX	Out of Service	1936	3,373,413	--
TK-3508	SO. ANNEX	Out of Service	1936	3,366,720	--
TK-3603	STIGLITZ PK.	Out of Service	1922	3,084,480	--
TK-3608	STIGLITZ PK.	Out of Service	1954	3,849,300	--
TK-3713	IND. TK FLD.	Out of Service	1944	3,357,600	--
TK-3903	J&L TK FLD.	Out of Service	1956	3,381,840	--
TK-6222		Out of Service	--	3,000	--
TK-6223		Out of Service	--	211,400	--
TK-6224		Out of Service	--	211,400	--
W-306	MWTP	Out of Service	--	--	--

(5) One (1) oil-water separator identified as the J & L Separator.

(6) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.27.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) and Benzene [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [326 IAC 14][40 CFR 61, Subpart J]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Pursuant to 40 CFR 61, Subpart J, the Permittee shall comply with the requirements specified in Section E.5 for leaks of benzene from pumps, pressure relief devices, sampling connection systems, open-ended lines or valves, and valves.

(d) Pursuant to 40 CFR 63.640(p), equipment that is subject to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart J is required only to comply with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

(e) Pursuant to 40 CFR 60, Subpart GGG, the Permittee shall comply with the requirements specified in Section E.13 for equipment leaks of VOC from compressors and other process equipment that is located at the J & L Tank Field and was modified after modified January 4, 1983. Pursuant to 40 CFR 63.640(p), equipment that is subject to both 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC are required to comply only with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

D.27.2 Petroleum Liquid Storage Facilities [326 IAC 8-4-3]

Pursuant to 326 IAC 8-4-3(a), the Permittee shall comply with the requirements in this condition for all petroleum liquid storage vessels with capacities greater than 39,000 gallons containing volatile organic compounds whose true vapor pressure is greater than 1.52 psi. Tanks subject to this condition include: 3474, 3475, 3476, 3477, 3480, 3482, 3483, 3484, 3486, 3487, 3488, 3489, 3493, 3511, 3512, 3513, 3514, 3525, 3526, 3527, 3528, 3531, 3532, 3533, 3549, 3553, 3554, 3558, 3601, 3605, 3629, 3639, 3641, 3701, 3702, 3703, 3704, 3707, 3716, 3728, 3730, 3900, 3904, 3905, 3907, 3909, 3911, 3912, 3914, 3916, 3917, 3918, 3919, 3920, ~~BT-002~~, 3492, 3529, 3631, 3637, 3706, 3860, and 3901.

Pursuant to 326 IAC 8-4-3(a), the Permittee shall comply with the following requirements for all petroleum liquid storage vessels with capacities greater than 39,000 gallons containing volatile organic compounds whose true vapor pressure is greater than 1.52 psi.

(a) Pursuant to 326 IAC 8-4-3(b), the Permittee shall not permit the use of an affected fixed roof tank unless:

(1) The tank has been retrofitted with an internal floating roof equipped with a closure seal, or seals, to close the space between the roof edge and tank wall unless the source has been retrofitted with equally effective alternate control which has been approved,

(2) The facility is maintained such that there are no visible holes, tears or other opening in the seal or any seal fabric or materials,

(3) All openings, except stub drains, are equipped with covers, lids or seals such that:

(A) the cover, lid or seal is in the closed position at all times except when in actual use;

(B) automatic bleeder vents are closed at all times except when in actual use;

(C) rim vents if provided, are set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

(b) Pursuant to 326 IAC 8-4-3(c)(1), the Permittee shall not store petroleum liquid in an affected open top tank having a cover consisting of a double deck or pontoon single deck which rests upon and is supported by the petroleum liquid being contained and is equipped with a closure seal or seals to close the space between the roof edge and tank wall shall not be used to store volatile organic liquids unless:

(1) The tank has been fitted with:

(A) a continuous secondary seal extending from the floating roof to the tank wall (rim-mounted secondary seal); or

(B) a closure or other device approved by the commissioner which is equally effective.

(2) All seal closure devices meet the following requirements:

(A) there are no visible holes, tears, or other openings in the seal(s) or seal fabric;

(B) the seal(s) are intact and uniformly in place around the circumference of the floating roof between the floating roof and the tank wall;

(C) for vapor mounted primary seals, the accumulated gap area around the circumference of the secondary seal where a gap exceeding one-eighth (1/8) inch exists between the secondary seal and the tank wall shall not exceed 1.0 square in per foot of tank diameter. There shall be no gaps exceeding one-half (½) inch between the secondary seal and the tank wall of welded tanks and no gaps exceeding one (1) inch between the secondary seal and the tank wall of riveted tanks.

(3) All openings in the external floating roof, except for automatic bleeder vents, rim space vents, and leg sleeves, are:

(A) equipped with covers. seals, or lids in the closed position except when the openings are in actual use; and

(B) equipped with projections into the tank which remain below the liquid surface at all times.

(4) automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports;

(5) rim vents are set to open when the roof is being floated off the leg supports or at the manufacturer's recommended setting ; and

(6) emergency roof drains are provided with slotted membrane fabric covers or equivalent covers which cover at least ninety percent (90%) of the opening.

D.27.3 Volatile Organic Liquid Storage Vessels [326 IAC 8-9]

Pursuant to 326 IAC 8-9, the Permittee shall comply with the following requirements for storage tanks 3529, 3901, 3902, 3912, 3477, 3482, 3483, 3492, 3510, 3512, 3513, 3532, 3624, 3631, 3633, 3635, 3639, 3641, 3705, 3706, 3709, 3728, 3730, 3905, 3909, 3914, 3511, 3601, 3480, 3486, 3487, 3525, 3526, 3553, 3554, 3605, 3703, 3704, 3533, 3915, 3916, 3917, 3918, 3919, 3920, D-424, F-011, TK-3546, TK-3547, TK-3548, TK-3567, TK-3867, TK-3868, TK-3869, TK-3872, TK-3876, TK-0563, TK-3228, TK-3234, TK-3464, TK-3465, TK-3468, TK-3491, TK-3496, TK-3498, TK-3499, TK-3500, TK-3505, TK-3509, TK-3569, TK-3606, TK-3607, TK-3609, TK-3610, TK-3611, TK-3613, TK-3711, TK-3712, TK-3714, TK-3717, TK-3718, TK-3719, TK-3720, TK-3721, TK-3722, TK-3723, TK-3726, TK-3733, TK-3735, TK-3908, TK-3910, TK-3913, TK-6078, TK-6113, TK-6114, TK-6125, TK-6126, TK-6127, TK-6128, TK-6129, TK-6148, TK-6149, TK-6150, TK-6153, TK-6248, TK-6249, TK-6250, TK-6251, TK-6252, TK-6253, TK-6261, TK-6262, TK-3571, TK-3572, TK-3734, and TK-3906. For Storage tanks 3534, 3602, 3604, 3708, 3727, D-424, F-011, TK-3546, TK-3547, TK-3548, TK-3567, TK-3867, TK-3868, TK-3869, TK-3872, TK-3876, TK-0563, TK-3228, TK-3234, TK-3464, TK-3465, TK-3468, TK-3491, TK-3496, TK-3498, TK-3499, TK-3500, TK-3505, TK-3509, TK-3569, TK-3606, TK-3607, TK-3609, TK-3610, TK-3611, TK-3613, TK-3711, TK-3712, TK-3714, TK-3717, TK-3718, TK-3719, TK-3720, TK-3721, TK-3722, TK-3723, TK-3726, TK-3733, TK-3735, TK-3908, TK-3910, TK-3913, TK-6078, TK-6113, TK-6114, TK-6125, TK-6126, TK-6127, TK-6128, TK-6129, TK-6148, TK-6149, TK-6150, TK-6153, TK-6248, TK-6249, TK-6250, TK-6251, TK-6252, TK-6253, TK-6261, TK-6262, TK-3571, TK-3572, TK-3734, and TK-3906, which are used to store liquids with vapor pressures less than 0.5 psia, the Permittee shall comply only with the **recordkeeping and** reporting requirements specified in Condition D.27.9(e). For storage tanks 3633, 3635, 3710, 3571, TK-3572, TK-3734, and TK-3906, which are used to store liquids with vapor pressures between 0.5 and 0.75 psia, the Permittee shall comply only with the requirements specified in Condition D.27.9(e) and (i).

(a) Pursuant to 326 IAC 8-9-4(a), the Permittee shall comply with the following requirements for each vessel having a capacity greater than or equal to thirty-nine thousand (39,000) gallons, that stores VOL with a maximum true vapor pressure greater than or equal to seventy-five hundredths (0.75) pound per square inch absolute (psia) but less than eleven and one-tenth (11.1) psia:

(1) On or before May 1, 1996, for each vessel having a permanently affixed roof, the Permittee shall install one (1) of the following:

(A) An internal floating roof meeting the standards in section (b) of this Condition.

(B) An equivalent emissions control system resulting in equivalent emissions reductions to that obtained in paragraph (a)(1)(A).

(2) For each vessel having an internal floating roof, install one (1) of the following:

(A) At the time of the next scheduled cleaning, but not later than ten (10) years after May 1, 1996, an internal floating roof meeting the standards in section (b) of this Condition,

(B) On or before May 1, 1996, an equivalent emissions control system resulting in equivalent emissions reductions to that obtained in paragraph (a)(2)(A).

(3) For each vessel having an external floating roof, install one (1) of the following:

(A) At the time of the next scheduled cleaning, but not later than ten (10) years after May 1, 1996, an external floating roof meeting the standards in section (c) of this Condition.

(B) On or before May 1, 1996, an equivalent emissions control system resulting in equivalent emissions reductions to that obtained in paragraph (a)(3)(A) of this condition.

(b) Pursuant to 326 IAC 8-9-4(c), for each internal floating roof, the Permittee shall comply with the following standards:

(1) The internal floating roof shall float on the liquid surface, but not necessarily in complete contact with it, inside a vessel that has a permanently affixed roof.

(2) The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the vessel is completely emptied or subsequently emptied and refilled.

(3) When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(4) Each internal floating roof shall be equipped with one (1) of the following closure devices between the wall of the vessel and the edge of the internal floating roof:

(A) A foam or liquid-filled seal mounted in contact with the liquid (liquid-mount seal).

(B) Two (2) seals mounted one (1) above the other so that each forms a continuous closure that completely covers the space between the wall of the vessel and the edge of the internal floating roof. The lower seal may be vapor mounted, but both shall be continuous.

(C) A mechanical shoe seal that consists of a metal sheet held vertically against the wall of the vessel by springs or weighted levers and that is connected by braces to the floating roof. A flexible coated fabric, or envelope, spans the annular space between the metal sheet and the floating roof.

(5) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents shall provide a projection below the liquid surface.

(6) Each opening in a noncontact internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains shall be equipped with a cover or lid that shall be maintained in a closed position at all times (with no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(7) Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(8) Rim space vents shall be equipped with a gasket and shall be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(9) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least ninety percent (90%) of the opening.

(10) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(c) Pursuant to 326 IAC 8-9-4(e), the Permittee shall comply with the following standards applicable to each external floating roof:

(1) Each external floating roof shall be equipped with a closure device between the wall of the vessel and the roof edge. The closure device shall consist of two (2) seals, one (1) above the other. The lower seal shall be referred to as the primary seal; the upper seal shall be referred to as the secondary seal.

(2) Except as provided in 326 IAC 8-9-5(c)(4), the primary seal shall completely cover the annular space between the edge of the floating roof and vessel wall and shall be either a liquid-mounted seal or a shoe seal.

(3) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the vessel in a continuous fashion except as allowed in 326 IAC 8-9-5(c)(4).

(4) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface.

(5) Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof shall be equipped with a gasketed cover, seal or lid that shall be maintained in a closed position at all times, without visible gap, except when the device is in actual use.

(6) Automatic bleeder vents shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(7) Rim vents shall be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents shall be gasketed.

(8) Each emergency roof drain shall be provided with a slotted membrane fabric cover that covers at least ninety percent (90%) of the area of the opening.

(9) The roof shall be floating on the liquid at all times, for example, off the roof leg supports, except when the vessel is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

D.27.4 VOC and HAP Emissions From Storage Vessels [326 IAC 12] [40 CFR 60, Subpart K] [40 CFR 60, Subpart Ka] [40 CFR 60, Subpart Kb] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 40 CFR 60.110a, storage vessels 3480, 3486, 3487, 3525, 3526, 3553, 3554, 3602, 3604, 3703, 3704, 3915, 3916, 3917, 3918, 3919, and 3920 are affected facilities under 40 CFR 60, Subpart Ka. Unless otherwise specified in paragraph (d) of this condition, the Permittee shall operate these storage tanks in compliance with the requirements specified in Section E.8. For storage tanks 3602 and 3604, the Permittee shall comply only with the record keeping requirements in Section E.8.

(b) Pursuant to 40 CFR 60.110b, storage vessels 3474, 3475, 3476, 3484, 3488, 3489, 3493, 3514, 3527, 3528, 3531, 3549, 3558, 3600, 3622, 3629, 3701, 3702, 3715, 3716, 3860, 3900, 3904, 3907, **TK-3637,** and 3911 are affected facilities under 40 CFR 60, Subpart Kb. Unless otherwise specified in paragraph (d) of this condition, the Permittee shall operate these storage tanks in compliance with the requirements specified in Section E.9.

(c) Pursuant to 40 CFR 60.110, storage vessels 3534, 3601, and 3605 are affected facilities under 40 CFR 60, Subpart K. Unless otherwise specified in paragraph (d) of this condition, the Permittee shall operate these storage tanks in compliance with the requirements specified in Section E.7.

(d) Pursuant to 40 CFR 63, Subpart CC,

(1) The Permittee shall comply with the requirements specified in Section E.1, for the following Group I storage vessels: 3477, 3474, 3475, 3476, 3480, 3482, 3483, 3484, 3486, 3487, 3488, 3489, 3493, 3510, 3511, 3512, 3513, 3514, 3525, 3526, 3527, 3528, 3529, 3531, 3532, 3534, 3537, 3533, 3553, 3554, 3601, 3605, 3624, 3629, 3631, 3633, 3635, 3637, 3639, 3641, 3701, 3702, 3703, 3704, 3705, 3706, 3707, 3710, 3715, 3716, 3728, 3900, 3901, 3902, 3904, 3905, 3907, 3909, 3912, 3914, 3915, 3916, 3917, 3918, 3919, and 3920.

(2) Pursuant to 40 CFR 63.640(n)(5), Group 1 storage vessels that are also subject to the provisions of 40 CFR 60, Subparts K or Ka are required to only comply with the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

(3) Pursuant to 40 CFR 63.640(n)(1), Group 1 and Group 2 storage vessels that are also subject to the provisions of 40 CFR Part 60, Subpart Kb, are required to comply only with the requirements of 40 CFR 60, Subpart Kb, except as provided in 40 CFR 63.640(n)(8).

D.27.5 Wastewater/Waste Streams [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [40 CFR 60 Subpart QQQ] [326 IAC 12]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements in Sections E.1 and E.3 for individual drain systems, oil-water separators, and closed vent systems and control devices.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems subject to 40 CFR, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, subpart CC specified in Section E.1.

D.27.6 Petroleum Refineries - Separators [326 IAC 8-4-2]

Pursuant to 326 IAC 8-4-2(2), the Permittee shall equip oil-water separators, forebay, and openings in covers with lids or seals such that the lids or seals are in the closed position at all times except when in actual use.

D.27.7 NESHAP for Organic Liquid Distribution [40 CFR 63, Subpart EEEE]

Pursuant to 40 CFR 63.2338(b), storage tank D-424 and any equipment at this source that meets the definition of an affected source under 40 CFR 63.2334 shall comply with the requirements of 40 CFR 63, Subpart EEEE, as specified in Section E.24.

Compliance Monitoring Requirements

D.27.~~7~~**8** Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

D.27.~~8~~**9** Storage Vessel Inspections [326 IAC 8-9]

(a) Pursuant to 326 IAC 8-9-5(a), the Permittee shall meet the requirements of paragraph (b), (c), or (d) for each vessel subject to 326 IAC 8-9-4(a):

(b) On and after May 1, 1996, except as provided in 326 IAC 8-9-4(a)(2), the Permittee shall meet the following requirements for each vessel equipped with an internal floating roof:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal, if one is in service, prior to filling the vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the Permittee shall repair the items before filling the vessel.

(2) For vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal, if one is in service, through manholes and roof hatches on the fixed roof at least once every twelve (12) months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the Permittee shall repair the items or empty and remove the vessel from service within forty-five (45) days. If a failure that is detected during inspections required in this section cannot be repaired in forty-five (45) days and if the vessel cannot be emptied within forty-five (45) days, a thirty (30) day extension may be requested from the department in the inspection report required in 326 IAC 8-9-6(c)(3). Such a request for an extension shall document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with both primary and secondary seals:

(A) visually inspect the vessel as specified in paragraph (b)(4) of this Condition, at least every five (5) years; or

(B) Visually inspect the vessel as specified in paragraph (b)(2) of this Condition.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal, if one is in service, gaskets, slotted membranes, and sleeve seals each time the vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than ten percent (10%) open area, the Permittee shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the vessel with VOL.

(5) In no event shall the inspections required by this Condition occur at intervals greater than ten (10) years in the case of vessels conducting the annual visual inspection as specified in paragraphs (b)(2) and (b)(3)(B) of this Condition and at intervals no greater than five (5) years in the case of vessels specified in subdivision (b)(3)(A).

(c) On and after May 1, 1996, except as provided in 326 IAC 8-9-4(a)(3), the Permittee shall meet the following requirements for each vessel equipped with an external floating roof:

(1) Determine the gap areas and maximum gap widths between the primary seal and the wall of the vessel and between the secondary seal and the wall of the vessel according to the following frequency:

(A) Measurements of gaps between the vessel wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within sixty (60) days of the initial fill with VOL and at least once every five (5) years thereafter.

(B) Measurements of gaps between the vessel wall and the secondary seal shall be performed within sixty (60) days of the initial fill with VOL and at least once per year thereafter.

(C) If any source ceases to store VOL for a period of one (1) year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for purposes of paragraph (c)(1) of this Condition.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(A) Measure seal gaps, if any, at one (1) or more floating roof levels when the roof is floating off the roof leg supports.

(B) Measure seal gaps around the entire circumference of the vessel in each place where a one-eighth (1/8) inch diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the vessel and measure the circumferential distance of each such location.

(C) The total surface area of each gap described in paragraph (c)(2)(B) of this Condition shall be determined by using probes of various widths to measure accurately the actual distance from the vessel wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each by the nominal diameter of the vessel and compare each ratio to the respective standards in paragraph (c)(4) of this Condition.

(4) Make necessary repairs or empty the vessel within forty-five (45) days of identification of seals not meeting the requirements listed in paragraphs (A) and (B) as follows:

(A) The accumulated area of gaps between the vessel wall and the mechanical shoe or liquid-mounted primary seal shall not exceed ten (10) square inches per foot of vessel diameter, and the width of any portion of any gap shall not exceed one and five-tenths (1.5) inches. There shall be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(B) The secondary seal shall meet the following requirements:

(i) The secondary seal shall be installed above the primary seal so that it completely covers the space between the roof edge and the vessel wall except as provided in paragraph (c)(2)(C) of this Condition.

(ii) The accumulated area of gaps between the vessel wall and the secondary seal used in combination with a metallic shoe or liquid-mounted primary seal shall not exceed one (1) square inch per foot of vessel diameter, and the width of any portion of any gap shall not exceed five-tenths (0.5) inch. There shall be no gaps between the vessel wall and the secondary seal when used in combination with a vapor-mounted primary seal.

(iii) There shall be no holes, tears, or other openings in the seal or seal fabric.

(C) If a failure that is detected during inspections required in paragraph (c) of this condition cannot be repaired within forty-five (45) days and if the vessel cannot be emptied within forty-five (45) days, a thirty (30) day extension may be requested from the department in the inspection report required in section 6(d)(3) of 326 IAC 8-9. Such extension request shall include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed. If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal fabric, the Permittee shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the vessel with VOL.

(d) For each vessel that is equipped with a closed vent system and control device described in 326 IAC 8-9-4(a)(1)(B), (a)(2)(B), or (a)(3)(B) and meeting the requirements of 326 IAC 8-9-4(d), other than a flare, the Permittee shall operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the department in accordance with 326 IAC 8-9-5(d)(1).

(e) For each vessel that is equipped with a closed vent system and a flare to meet the requirements in 326 IAC 8-9-4(a)(4) or (d), the Permittee shall meet the requirements specified in the general control device requirements in 40 CFR 60.18(e) and 40 CFR 60.18(f)

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.27.~~9~~**10**Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 ~~and to document compliance with Condition D.27.1(a)~~, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC ~~and to document compliance with Condition D.27.1(b)~~, the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 61, Subpart J, ~~and to document compliance with Condition D.27.1(c)~~, the Permittee shall keep records as specified in Section E.5.

(d) Pursuant to 326 IAC 8-4-3(d) ~~and to document compliance with Condition D.27.2~~, the Permittee shall maintain the following records for storage vessels subject to 326 IAC 8-4-3:

(1) type of petroleum liquid stored,

(2) maximum true vapor pressure to the liquid as stored, and

(3) results of inspections performed on storage vessels.

(e) Pursuant to 326 IAC 8-9-6(b) ~~and to document compliance with Condition D.27.3~~, the Permittee shall maintain, for the life of the vessel, a record of the following for each vessel to which 326 IAC 8-9 applies:

(1) The vessel identification number,

(2) The vessel dimensions,

(3) The vessel capacity, and

(4) A description of the emission control equipment for each vessel described in section 4(a) or 4(b) of 326 IAC 8-9, or a schedule for installation of emission control equipment on vessels described in section 4(a) or 4(b) of 326 IAC 8-9 with a certification that the emission control equipment meets the applicable standards.

(f) Pursuant to 326 IAC 8-9-6(c) ~~and to document compliance with Condition D.27.3(a)~~, the Permittee shall maintain the following records for each vessel equipped with a permanently affixed roof and internal floating roof:

(1) A record of each inspection performed as required by section 5(b)(1) through 5(b)(4) of 326 IAC 8-9. Each record shall identify the following:

(A) The vessel inspected by identification number.

(B) The date the vessel was inspected.

(C) The observed condition of each component of the control equipment, including the following:

(i) Seals

(ii) Internal floating roof.

(iii) Fittings

(2) If any of the conditions described in 326 IAC 8-9-5(b)(2) are detected during the required annual visual inspection, a record that includes the following shall be maintained:

(A) The vessel by identification number.

(B) The nature of the defects.

(C) The date the vessel was emptied or the nature of and date the repair was made.

(3) After each inspection required by 326 IAC 8-9-5(b)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in 326 IAC 8-9-5(b)(3)(B) a record that includes the following shall be maintained:

(A) The vessel by identification number.

(B) The reason the vessel did not meet the specifications of 326 IAC 8-9-4(a)(1)(A), 8-9-4(a)(2)(A), or 8-9-5(b) and list each repair made.

(g) Pursuant to 326 IAC 8-9-6(d) ~~and to document compliance with Condition D.27.8(c)~~, the Permittee shall comply with the following record keeping requirements for each vessel equipped with an external floating roof:

(1) Keep a record of each gap measurement performed as required by section 5(c) of 326 IAC 8-9. Each record shall identify the vessel in which the measurement was made and shall contain the following:

(A) The date of measurement.

(B) The raw data obtained in the measurement.

(C) The calculations described in section 5(c)(2) and 5(c)(3) of 326 IAC 8-9.

(2) For each seal gap measurement that detects gaps exceeding the limitations specified in section 5(c) of 326 IAC 8-9, the Permittee shall maintain a record of the following:

(A) The date of measurement.

(B) The raw data obtained in the measurement.

(C) The calculations described in section 5(c)(2) and 5(c)(3) of 326 IAC 8-9.

(D) The date the vessel was emptied or the repairs made and date of repair.

(h) Pursuant to 326 IAC 8-9-6(e) ~~and to document compliance with Condition D.27.4(a)~~, the Permittee shall comply with the following record keeping requirements for any vessel with a closed vent system with a control device:

(1) The Permittee shall maintain records of the following for any vessel equipped with a control device other than a flare:

(A) The operating plan.

(B) Measured values of the parameters monitored according to section 5(d)(2) of 326 IAC 8-9.

(2) The Permittee shall meet the following requirements for any vessel equipped with a closed vent system and a flare:

(A) Keep records of all periods of operation during which the flare pilot flame is absent.

(B) Keep records of measurements required by 40 CFR 60.18(f)(1) through 40 CFR 60.18(f)(5) as required by 40 CFR 60.8.

(i) Pursuant to 326 IAC 8-9-6(g) and (h), the Permittee shall maintain the following records for storage tanks 3633, 3635, 3710, 3571, TK-3572, TK-3734, and TK-3906, which have a design capacity greater than or equal to thirty-nine thousand (39,000) gallons and store a VOL with a maximum true vapor pressure greater than or equal to 0.5 but less than 0.75 pound per square inch absolute (psia):

(1) The type of VOL stored.

(2) The dates of the VOL stored.

(3) For each day of VOL storage, the average stored temperature for VOLs stored above or below the ambient temperature or average ambient temperature for VOLs stored at ambient temperature, and the corresponding maximum true vapor pressure.

(4) The Permittee shall maintain a record and notify the department within thirty (30) days when the maximum true vapor of the liquid exceeds 0.75 psia.

(j) Pursuant to 40 CFR 60, Subpart Ka ~~and to document compliance with Condition D.27.4(a)~~, the Permittee shall maintain records as specified in Section E.8.

(k) Pursuant to 40 CFR 60, Subpart Kb ~~and to document compliance with Condition D.27.4(b)~~, the Permittee shall maintain records as specified in Section E.9.

(l) Pursuant to 40 CFR 60, Subpart K ~~and to document compliance with Condition D.27.4(c)~~, the Permittee shall maintain records as specified in Section E.7.

(m) Pursuant to 40 CFR 63, Subpart CC ~~and to document compliance with Condition D.27.4(d)~~, the Permittee shall maintain records as specified in Section E.1.

(n) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF ~~and to document compliance with Condition D.27.5(a)~~, the Permittee shall keep records as specified in Sections E.1 and E.3.

(o) Pursuant to 40 CFR 60, Subpart QQQ ~~and to document compliance with Condition D.27.5(b)~~, the Permittee shall keep records as specified in Section E.6.

(p) Pursuant to 40 CFR 60, Subpart GGG ~~and to document compliance with Condition D.27.2(e)~~, the Permittee shall keep records as specified in Section E.13.

(q) Pursuant to 40 CFR 63, Subpart EEEE, the Permittee shall keep records as specified in Section E.24.

D.27.~~10~~**11** Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.27.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.27.1(b), the Permittee shall submit reports as specified in Section E.1 and E.4.

(c) Pursuant to 40 CFR 61, Subpart J, and to document compliance with Condition D.27.1(c), the Permittee shall submit reports as specified in Section E.5.

(d) Pursuant to 326 IAC 8-9-6(c) and to document compliance with Condition D.27.2(a):

(1) If any of the conditions described in 326 IAC 8-9-5(b)(2) are detected during the required annual visual inspection, the Permittee shall furnish a report to the department within (30) days of the inspection. Each report shall identify the following:

(A) The vessel by identification number.

(B) The nature of the defects.

(C) The date the vessel was emptied or the nature of and date the repair was made.

(2) After each inspection required by 326 IAC 8-9-5(b)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in 326 IAC 8-9-5(b)(3)(B), the Permittee shall furnish a report to the department within thirty (30) days of the inspection. The report shall identify the following:

(A) The vessel by identification number.

(B) The reason the vessel did not meet the specifications of section 4(a)(1)(A), 4(a)(2)(A), or 5(b) of 326 IAC 8-9 and list each repair made.

(e) Pursuant to 326 IAC 8-9-6(d) and to document compliance with Condition **D.27.9(c)** ~~D.27.8(c)~~:

(1) Within sixty (60) days of performing the seal gap measurements required by section 5(c)(1) of 326 IAC 8-9, the Permittee shall furnish the department with a report that contains the following:

(A) The date of measurement.

(B) The raw data obtained in the measurement.

(C) The calculations described in section 5(c)(2) and 5(c)(3) of 326 IAC 8-9.

(2) After each seal gap measurement that detects gaps exceeding the limitations specified in section 5(c) of 326 IAC 8-9, the Permittee shall submit a report to the department within thirty (30) days of the inspection. The report shall identify the vessel and contain the following information:

(A) The date of measurement.

(B) The raw data obtained in the measurement.

(C) The calculations described in section 5(c)(2) and 5(c)(3) of 326 IAC 8-9.

(D) The date the vessel was emptied or the repairs made and date of repair.

(f) Pursuant to 326 IAC 8-9-6(e) and to document compliance with Condition D.27.3(a), the Permittee shall meet the following requirements for any vessel equipped with a closed vent system and a flare:

(1) Furnish the department with a report containing the measurements required by 40 CFR 60.18(f)(1) through 40 CFR 60.18(f)(5) as required by 40 CFR 60.8. This report shall be submitted within six (6) months of the initial start-up date.

(2) Furnish the department with a semiannual report of all periods recorded under 40 CFR 60.115 in which the pilot flame was absent.

(g) Pursuant to 326 IAC 8-9-5(b)(5) and 326 IAC 8-9-5(c)(6)(B), the Permittee shall notify the department in writing at least thirty (30) days prior to the filling or refilling of each vessel for which an inspection is required by 326 IAC 8-9-5(b)(1) to afford the department the opportunity to have an observer present. If the inspection required by 326 IAC 8-9-5(b)(4) or (c)(6) is not planned and the Permittee could not have known about the inspection thirty (30) days in advance of refilling the vessel, the Permittee shall notify the department at least seven (7) days prior to the refilling of the vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification, including the written documentation, may be made in writing and sent by express mail so that it is received by the department at least seven (7) days prior to the refilling.

(h) The Permittee shall notify the department in writing at least thirty (30) days prior to the filling or refilling of each vessel to afford the department the opportunity to inspect the vessel prior to the filling. If the inspection required by this subdivision is not planned and the Permittee could not have known about the inspection thirty (30) days in advance of refilling the vessel, the Permittee shall notify the department at least seven (7) days prior to the refilling of the vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the department at least seven (7) days prior to the refilling.

(i) Pursuant to 326 IAC 8-9-5(c)(5), the Permittee shall notify the department thirty (30) days in advance of any gap measurements required by 326 IAC 8-9-5(c)(1) to afford the department the opportunity to have an observer present.

(j) Pursuant to 40 CFR 60, Subpart Ka and to document compliance with Condition D.27.4(a), the Permittee shall submit reports as specified in Section E.8.

(k) Pursuant to 40 CFR 60, Subpart Kb and to document compliance with Condition D.27.4(b), the Permittee shall submit reports as specified in Section E.9.

(l) Pursuant to 40 CFR 60, Subpart K and to document compliance with Condition D.27.4(c), the Permittee shall submit reports as specified in Section E.7.

(m) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.27.4(d), the Permittee shall submit reports as specified in Section E.1.

(n) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.27.5(a), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(o) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.27.5(b), the Permittee shall submit reports as specified in Section E.6.

(p) To document compliance with Condition D.27.4(d)(2), the Permittee shall submit the following reports:

Pursuant to 40 CFR 63.654(g)(6), the Permittee shall submit Notification of Compliance Status reports no later than 60 days after the end of the 6-month period after an existing Group 1 storage tank was brought into compliance. The Notification of Compliance Status Report may be combined with the periodic report. The notifications shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
and
United States Environmental Protection Agency, Region V
Director, Air and Radiation Division
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

The notifications require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(q) Pursuant to 40 CFR 60, Subpart GGG and to document compliance with Condition D.27.2(e), the Permittee shall submit reports as specified in Section E.13.

(r) Pursuant to 40 CFR 63, Subpart EEEE, the Permittee shall submit reports as specified in Section E.24.

SECTION D.31 FACILITY OPERATION CONDITIONS - Cooling Tower

Facility Description [326 IAC 2-7-5(15)]

(ee) ~~Cooling Towers constructed after 1995:~~ **Cooling Towers, including the following:**

(1) One (1) cooling tower (identified as Cooling Tower No.6), constructed in 1996, with a maximum capacity of 20,000 gallons of water per minute. Cooling Tower No.6 is located at the No.12 Pipestill.

(2) Cooling Towers (constructed prior to 1980) with controls installed as part of the CXHO project:

Cooling Tower	Recirculation Rate/Make-up rate (gallons/minute)	Control Devices
Cooling Tower 2*	**50,000/1,285**	**high efficiency liquid drift eliminators**
Cooling Tower 3	**90,000/1,571**	**high efficiency liquid drift eliminators**
Cooling Tower 4	**44,000/1,085**	**high efficiency liquid drift eliminators**

*** Half of the Cooling Tower 2 modules were controlled prior to the CXHO Project. Contemporaneous to the CXHO Project the other modules will be controlled with high efficiency drift eliminators.**

(3) Cooling Towers to be installed as part of the CXHO project:

Cooling Tower 7	**21,000/451**	**high efficiency liquid drift eliminators**
Cooling Tower 8	**90,000/2956**	**high efficiency liquid drift eliminators**

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.31.1 **Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and** Emission Offset [326 IAC 2-3]

(a) ~~Pursuant to~~ **In order to render** 326 IAC 2-3 (Emission Offset) **not applicable and pursuant to** CP089-4822-00003, issued April 19, 1996, the average concentration of total dissolved solids (TDS) in the water input to Cooling Tower No.6 shall not exceed 3,300 mg/L based on a twelve (12) consecutive month period, with compliance determined at the end of each month. ~~This limit is equivalent to 27.5 tons per year of PM and PM_{10} emissions.~~

(b) ~~Pursuant to~~ **In order to render** 326 IAC 2-3 (Emission Offset) **not applicable and pursuant to** CP089-4822-00003, issued April 19, 1996, the VOC emissions from Cooling Tower No.6 shall not exceed 0.84 pounds per hour~~, which is equivalent to 3.7 tons per twelve (12) consecutive month period~~.

Compliance with these limits **shall** ensure~~s~~ that 326 IAC 2-3 does not apply to **Cooling Tower No. 6**.

(c) In order to render 326 IAC 2-2 and 326 IAC 2-1.1-5 not applicable, after the installation of the liquid drift eliminators on cooling towers 2, 3, 4, and the installation of towers 7 and 8, the average concentration of total dissolved solids (TDS) in the water input to Cooling Towers No. 2, 3, 4, 7, and 8 shall not exceed the following:

Cooling Tower	TDS (mg/L) per twelve (12) consecutive month period
2	**1,627**
3	**1,147**
4	**1,645**
7	**1,163**
8	**1,163**

(d) In order to render 326 IAC 2-3 (Emission Offset) not applicable, the VOC emissions from Cooling Towers No., 7 and 8 shall not exceed the following based on a 12 consecutive month average:

Cooling Tower	lb/hr
7	**0.9**
8	**3.9**

Compliance with the VOC, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for VOC, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

Compliance Determination Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.31.2 Operating Requirements

In order to demonstrate compliance with Condition D.31.1(c), the liquid drift eliminators shall be in operation and control PM and PM-10 from Cooling Towers 2, 3, 4, 7 and 8 at all times that these cooling towers are in operation.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.31.~~2~~**3** Compliance Monitoring Requirements [326 IAC 2-3]

(a) To monitor compliance with Condition D.31.1(a) **and (c)**, the Permittee shall take weekly measurements of the total dissolved solids (TDS) in the water input to Cooling Tower**s** No. **2, 3, 4, 6, 7 and 8.** If the TDS limitation is exceeded, the Permittee shall perform quantitative water analyses and shall take the remedial action necessary to correct the problem.

(b) To monitor compliance with Condition D.31.1(b) **and (d)**, the Permittee shall visually inspect the water going to Cooling Towers No. **2, 3, 4,** 6, **7 and 8** for liquid VOC, including but not limited to the indication of a sheen, at least once per week. If VOC is observed, the Permittee will take the remedial action necessary to correct the problem.

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.31.~~3~~**4** Record Keeping Requirements [326 IAC 2-3]

(a) To document compliance with Condition D.31.1(a) **and (c)**, and ~~D.31.2(a)~~ **31.3(a)**, the Permittee shall maintain records of the total dissolved solids (TDS) in the water input to Cooling Towers No. **2, 3, 4,** 6, **7 and 8** and any remedial actions taken (including the date remedial actions were initiated).

(b) To document compliance with Condition D.31.1(b) **and (d)** and ~~D.31.2(b)~~ **D.31.3(b)**, the Permittee shall maintain records of the visual inspects required by ~~D.31.2(b)~~ **D.31.3(b)** and any remedial actions taken (including the date remedial actions were initiated).

SECTION D.34 FACILITY OPERATION CONDITIONS - Marine Dock Facility

Facility Description [326 IAC 2-7-5(15)]

(ii) One (1) Marine Dock Facility used to store and transfer products. The facility has three dock berths. A process heater is used to keep certain tanks at the proper temperature for shipping. **As part of the CXHO Project, a vapor recovery/control system will be installed on the Marine Dock Loading operations to control emissions from gasoline loading.** This facility includes the following emission sources and may ~~also~~ include insignificant activities listed in Section A.4 of this permit:

(1) One (1) natural gas-fired process heater (identified as Marine Dock Heater F-100), having a maximum heat input capacity of 7 MMBtu per hour.

(2) One (1) storage tank (identified as BT-1), constructed in 1990, with a maximum storage capacity of 706,000 gallons and used to store petroleum hydrocarbons with a vapor pressure less than 15 psia. The tank is equipped with a fixed roof and an internal floating roof.

(3) One storage tank (BT-002), constructed in 1968, permitted for modification per SPM 089-25488-00453, with a maximum storage capacity of 874,944 gallons, used to store petroleum hydrocarbons with a vapor pressure less than 15 psia, with a fixed roof and an internal floating roof.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.34.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-3-6]

Pursuant to 326 IAC 6.8-6-3 (formerly 326 IAC 6-1-10.1(h)), the Permittee shall comply with the following requirements for process heater F-100:

(a) Only natural gas shall be burned as fuel; and

(b) The PM_{10} emissions shall not exceed **0.0075** ~~0.003~~ pounds per million Btu heat input and **0.052** ~~0.020~~ pounds per hour.

D.34.2 Emission Offset [326 IAC 2-3] Minor Limit

In order to render 326 IAC 2-3 not applicable, the Permittee shall comply with the following limits for gasoline loading operations at the marine loading dock:

(a) The VRU/VCU shall be installed and operated as part of the CXHO project.

(b) After the installation of the Vapor Recover Unit (VRU) or Vapor Capture Unit (VCU) on the marine loading dock, the emissions of VOC during gasoline loading shall not exceed 10 milligrams per liter (mg/L) of gasoline loaded.

(c) After the installation of the Vapor Recover Unit (VRU) or Vapor Capture Unit (VCU) on the marine loading dock, the gasoline loaded shall not exceed 4,000,000 barrels per 12 consecutive month period, with compliance determined at the end of each month.

(d) The additional NOx and CO emissions from the VRU/VCU shall not exceed 5.6 tons and 2.2 tons per 12 consecutive month period, respectively, with compliance determined at the end of each month,

Compliance with the VOC, NOx and CO emissions limit, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for VOCand CO for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-3 not applicable for these pollutants.

D.34.~~2~~**3** Wastewater/Waste Streams [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 14] [40 CFR 61, Subpart FF]

Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems and oil-water separators.

D.34.~~3~~**4** Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) and Benzene [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAPs from pumps, valves, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

D.34.~~4~~**5** Standards for Marine Tank Loading [326 IAC 20-17] [40 CFR 63, Subpart Y] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC and Y, the Permittee shall comply with the requirements specified in Section E.1 and E.12 for the Marine Dock Facility.

D.34.~~5~~**6** Petroleum Liquid Storage Facilities [326 IAC 8-4-3]

Pursuant to 326 IAC 8-4-3(b), the Permittee shall not permit the storage of a VOC with a true vapor pressure greater than 1.52 psia (10.5 kPa) in a fixed roof tank with a capacity greater than 39,000 gallons unless:

(a) The tank has been retrofitted with an internal floating roof equipped with a closure seal, or seals, to close the space between the roof edge and tank wall unless the source has been retrofitted with equally effective alternate control which has been approved,

(b) The facility is maintained such that there are no visible holes, tears or other opening in the seal or any seal fabric or materials,

(c) All openings, except stub drains, are equipped with covers, lids or seals such that:

(1) the cover, lid or seal is in the closed position at all times except when in actual use;

(2) automatic bleeder vents are closed at all times except when in actual use;

(3) rim vents if provided, are set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

D.34.~~6~~**7** VOC and HAP Emissions From Storage Vessels [326 IAC 12] [40 CFR 60, Subpart Kb] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

(a) Pursuant to 40 CFR 60, Subpart Kb and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in ~~Sectons~~ **Sections** E.1 and E.9 for storage tank**s** BT-1 **and BT-002**.

(b) Pursuant to 40 CFR 63.640(n)(1), a Group 1 or Group 2 storage vessel that is subject to 40 CFR 63, Subpart CC and to the provisions of 40 CFR 60, Subpart Kb is required to comply only with the requirements of 40 CFR 60, Subpart Kb except as provided in 40 CFR 63.640(n)(8), which are listed in Section E.1.

~~D.34.7 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements specified in Section E.20 for Marine Dock Heater F-100, which comprises the affected source for the small gaseous fuel subcategory.~~

Compliance Determination Requirements

D.34.8 Operating Requirement

Pursuant to SSM 089-14630-00003, issued on November 30, 2001, fuel oil shall not be used as fuel for process heater F-100, effective June 1, 2003.

D.34.9 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

(a) Within 180 days of the installation of the VRU or VCU at the marine loading dock, in order to demonstrate compliance with Condition D.34.2, the Permittee shall perform VOC testing at the outlet of the VRU/VCU when loading gasoline utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C - Performance Testing. This test shall be repeated at least once every five years from the date of the previous valid compliance demonstration.

(b) Compliance with the emissions limit for the VRU/VCU shall be determined as follows:

$$T = \left(\sum_{i=1}^{n} T_i\right) / n$$

Where:

T = average of IDEM approved stack test results over the previous 12 month period
T_i = average of multiple runs during Test #i
n = number of IDEM approved stack tests during previous 12 month period

D.34.10 Operating Requirement

After the installation of the VRU/VCU at the marine loading dock, in order to demonstrate compliance with Condition D.34.2, the VRU/VCU shall be in operation and control VOC emissions at all times gasoline loading is being performed at the marine loading dock.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.34.~~9~~**11** Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.34.~~10~~**12** Record Keeping Requirements

(a) To document compliance with Condition D.34.8 the Permittee shall maintain records of the type of fuel burned in Process Heater F-100.

(b) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.34.4(a)** ~~D.34.3(a)~~, the Permittee shall comply with the record keeping requirements in the LDAR Plan.

(c) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.34.4(b)** ~~D.34.3(b)~~, the Permittee shall comply with the record keeping requirements in Sections E.1 and E.4.

(d) Pursuant to 326 IAC 8-4-3(d) and to document compliance with Condition **D.34.6** ~~D.34.5~~, the Permittee shall maintain the following records for storage tank**s** BT-1 **and BT-002**:

(1) The type of petroleum liquid stored;

(2) The maximum true vapor pressure to the liquid as stored; and

(3) The results of inspections performed on the storage vessel.

(e) Pursuant to 40 CFR 60, Subpart Kb and 40 CFR 63, Subpart CC and to document compliance with Condition **D.34.7** ~~D.34.6~~, the Permittee shall comply with the record keeping requirements in Sections E.1 and E.9.

(f) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.34.3** ~~D.34.2~~, the Permittee shall keep records as specified in Sections E.1 and E.3.

(g) Pursuant to 40 CFR 63, Subparts CC and Y and to document compliance with Condition **D.34.5** ~~D.34.4~~, the Permittee shall maintain records of as specified in Sections E.1 and E.12.

(d) In order to demonstrate compliance with Condition D.34.2, the Permittee shall maintain records of barrels of gasoline loaded each month at the marine loading dock.

D.34.~~11~~**13**Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.34.4(a)** ~~D.34.3(a)~~, the Permittee shall comply with the reporting requirements in the LDAR Plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.34.4(b)** ~~D.34.3(b)~~, the Permittee shall comply with the reporting requirements specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 60, Subpart Kb and 40 CFR 63, Subpart CC and to document compliance with Condition **D.34.7** ~~D.34.6~~, the Permittee shall comply with the reporting requirements specified in Sections E.1 and E.9.

(d) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.34.3** ~~D.34.2~~, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(e) In order to demonstrate compliance with Condition D.34.2, following the installation of the VRU/VCU at the marine loading dock, the Permittee shall submit quarterly reports of the barrels of gasoline loaded at the marine loading dock. The report submitted by the Permittee does require the certification by the "Responsible Official" as defined by 326 IAC 2-7-1(34).

SECTION D.35 FACILITY OPERATION CONDITIONS – Hydrocarbon Flares

Facility Description [326 IAC 2-7-5(15)]

(jj) The refinery operates ~~eight~~ ten hydrocarbon flares. The PIB flare is operated by INEOS. The flares are used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

The flares are identified as follows:

Flare	Stack ID.	Date of Installation	Dimensions	Process Units Normally Controlled by the Flare System *	Maximum Capacity (MMBtu/hr)	Pilot Fuel Type
4UF Flare	224-06	1972	H = 200 ft, D = 2.5 ft.	ARU, CFU, BOU, 4UF	15,000	Fuel Gas and Natural Gas
FCU flare	230-02	1945	H = 200 ft. D = 2.0 ft.	FCU 600	5620	Fuel Gas and Natural Gas
UIU Flare	220-04	1958	H = 199.5 ft. D = 2.5 ft.	ISOM, 3UF, 2TP, CRU	7550	Fuel Gas and Natural Gas
VRU Flare	241-01	Unknown	H = 200 ft. D = 2.0 ft.	VRU 100,VRU200, VRU 300, FCU 500	1596	Fuel Gas and Natural Gas
Alky Flare	140-01	1961	H = 199.5 ft D = 2.5 ft.	PCU, Alky	3920	Fuel Gas and Natural Gas
SRU Flare	162-03	1971	H = 300 ft. D = 1.5 ft.	SRU	688	Fuel Gas and Natural Gas
DDU Flare	698-02	1993	H = 200 ft. D = 1.5 ft.	DDU, HU, Coker, DHT	6000	Fuel Gas and Natural Gas
LPG Flare	604-01	1986	H = 50 ft. D = 1.2 ft.	LPG storage vessels and loading facilities	30	LPG
PIB Flare**	2	1982	H = 250 ft. D = 3.0 ft.	RGP/PGP Loading Rack	540,000 lb/hr	Fuel Gas and Natural Gas
GOHT Flare* **	**802-03**	**Installed as Part of CXHO**	**H = 316 ft. D = 3.5 ft**	**GOHT**	**TBD**	**Fuel Gas and Natural Gas**
South Flare* **	**800-04**	**Installed as Part of CXHO**	**H = 350 ft. D = 5 ft**	**New Coker (#2 Coker), 12PS, Sulfur Recovery Complex**	**TBD**	**Fuel Gas and Natural Gas**

* - During emergencies or flare outages, some emission units or streams may be controlled by an alternate flare system that complies with the same applicable requirements as the flare normally used to control the emissions for those units.

** - Owned and operated by INEOS USA, LLC. (Plant I.D. 089-00076).

***** - Flares are equipped with a flare gas recovery system. Under normal operation the recovered gas streams will be sent to vapor recovery/treating area for removal of H_2S and heavy components before being utilized in the refinery fuel gas system.**

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.35.1 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for the GOHT Flare and the South Flare:

(a) The emissions of NOx shall not exceed 100 pounds per million cubic feet and 0.068 pounds per million BTU of pilot and purge gas burned.

(b) The emissions of VOC shall not exceed 5.5 pounds per million cubic feet and 0.14 pounds per million BTUof pilot and purge gas burned.

(c) The emissions of CO shall not exceed 84 pounds per million cubic feet and 0.37 pounds per million BTU of pilot and purge gas burned.

(d) The emissions of SO2 shall not exceed 0.6 pounds per million cubic feet of pilot gas burned.

(e) The emissions of SO2 shall not exceed 13.3 pounds per million cubic feet of purge gas burned.

(f) The emissions of PM and PM-10 shall not exceed 1.9 and 7.6 pounds per million cubic feet of pilot and purge gas burned.

(g) The Permittee shall comply with the following fuel usage limits:

Flare ID	Fuel Usage Limit (10^3 cubic feet per 12 consecutive month period)
GOHT-pilot	3,679.2
GOHT-purge	24,703.2
South flare-pilot	3,679.2
South flare-purge	28,908.0

Compliance with the fuel usage limits and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant thresholds at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.35.~~1~~**2** Standards for Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Section E.1 for the UIU, VRU, **GOHT, South** and Alky flares relating to the control of process vents.

D.35.~~2~~**3** Equipment Leaks of Benzene [326 IAC 14][40 CFR 61, Subpart J]

Pursuant to 40 CFR 61, Subpart J, the Permittee shall comply with the requirements specified in Section E.5 for control device standards for the 4UF Flare.

D.35.~~3~~**4** Equipment Leaks of VOC [326 IAC 12] [40 CFR 60, Subpart GGG]

Pursuant to 40 CFR 60, Subpart GGG, the Permittee shall comply with the control device standards specified in Section E.13 for the 4UF, UIU, Alky, **GOHT, South and** DDU flares.

D.35.~~4~~**5** Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

(a) Pursuant to 40 CFR 60, Subpart J, the Permittee shall comply with the requirements specified in Section E.2 for the DDU Flare, **GOHT flare, South flare** and LPG Flare, except as specified in paragraphs (b).

(b) To demonstrate compliance with paragraph (a) of this condition, the Permittee shall operate the LPG Flare in compliance with the approved alternative monitoring requirements in Condition D.35.~~5~~**7**.

D.35.~~5~~**6** Compliance Monitoring Requirements for the LPG Flare [326 IAC 12] [40 CFR 60, Subpart J]

The Permittee shall comply with the following alternative compliance monitoring requirements for the LPG Flare:

(a) The Permittee shall burn only certified commercial grade LPG in the LPG Flare.

(b) On May 13, 2004, the Permittee completed a detection tube sampling and analysis of the gas stored at the LPG storage facilities and determined that the total sulfur content of the gas is 34 ppm. No further testing is required.

(c) If the gas stream composition changes or if the gas stream will no longer be required to meet product or pipeline specifications, then the gas stream must be resubmitted for approval.

D.35.~~6~~**7** Operating Requirements for the Flares

The Permittee may route emissions to an alternate flare during emergencies or flare outages. The alternative flare shall be in compliance with the same requirements applicable to the flare normally used to control the emissions, except in cases of emergencies or malfunctions. Use of a flare as part of normal operation, which is not in compliance with the same applicable requirements as the flare normally used to control emissions, shall require prior approval by IDEM, OAQ.

D.35.~~7~~**8** NESHAP for Petroleum Refineries [40 CFR 63, Subpart UUU]

Pursuant to 40 CFR 63, Subpart UUU, the Permittee shall comply with the requirements specified in Section E.10 for the 4UF and UIU flares.

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.35.~~8~~**9** Record Keeping Requirements

(a) To document compliance with Condition **D.35.2** ~~D.35.1,~~ **Pursuant to 40 CFR 63, Subpart CC**, the Permittee shall maintain the records as specified in Section E.1.

(b) Pursuant to 40 CFR 61, Subpart J and to document compliance with Condition **D.35.3** ~~D.35.2~~, the Permittee shall keep records as specified in Section E.5.

(c) Pursuant to 40 CFR 60, Subpart GGG and to document compliance with Condition **D.35.4** ~~D.35.3~~, the Permittee shall maintain the records as specified in Section E.13.

(d) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.35.5** ~~D.35.4~~, the Permittee shall keep records as specified in Section E.2.

(e) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition **D.35.8** ~~D.35.7~~, the Permittee shall keep records as specified in Section E.10.

(f) **In order to demonstrate compliance with Condition D.35.1(e), the Permittee shall maintain records of fuel usages at the GOHT and South flares.**

D.35.~~9~~**10** Reporting Requirements

(a) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition **D.35.2** ~~D.35.1~~, the Permittee shall submit reports as specified in Section E.1.

(b) Pursuant to 40 CFR 61, Subpart J and to document compliance with Condition **D.35.3** ~~D.35.2~~, the Permittee shall submit reports as specified in Section E.5.

(c) Pursuant to 40 CFR 60, Subpart GGG and to document compliance with Condition **D.35.4** ~~D.35.3~~, the Permittee shall submit reports as specified in Section E.13.

(d) Pursuant to 40 CFR 60, Subpart J and to document compliance with Condition **D.35.5** ~~D.35.4~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(e) Pursuant to 40 CFR 63, Subpart UUU and to document compliance with Condition **D.35.8** ~~D.35.7~~, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.10.

(f) **In order to demonstrate compliance with Condition D.35.1, the Permittee shall submit quarterly reports for pilot gas and purge gas usages at the GOHT and South flares. The report submitted by the Permittee does require the certification by the "Responsible Official" as defined by 326 IAC 2-7-1(34).**

SECTION D.36 FACILITY OPERATION CONDITIONS – OSBL

Facility Description [326 IAC 2-7-5(15)]

(kk) The OSBL area includes the pipe alleys, laboratory dock and waste transfer pad. The pipe alleys contain pipes that transfer hydrocarbon streams from one process unit to another or to storage. This facility includes leaks from process equipment, including open-ended valves or lines and flanges. This facility also contains area drains and an oil/water separator. This facility may include insignificant activities listed in section A.4 of this permit."

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.36.1 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC**] [326 IAC 12] [40 CFR 60, Subpart GGGa]**

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Prior to start-up of the new coker (#2 Coker), BP shall make a determination as to whether 40 CFR 60, Subpart GGGa has been triggered by component changes made on the OSBLas a part of the projects authorized by SSM 089-25484-00463. BP shall report the results of that determination to IDEM. If BP determines that Subpart GGGa has been triggered, BP shall comply with the requirements of that rule upon startup.

D.36.2 Wastewater / Waste Streams [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [326 IAC 12] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and closed vent systems and control devices subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and closed vent systems and control devices subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, subpart CC specified in Section E.1.

Compliance Monitoring Requirements

D.36.3 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.36.4 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.36.1(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.36.1(b), the Permittee shall keep records as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.36.2(a), the Permittee shall keep records as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.36.2(b), the Permittee shall keep records as specified in Section E.6.

D.36.5 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.36.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 63, Subpart CC and to document compliance with Condition D.36.1(b), the Permittee shall submit reports as specified in Sections E.1 and E.4.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition D.36.2(a), the Permittee shall submit reports as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition D.36.2(b), the Permittee shall submit reports as specified in Section E.6.

SECTION D.37 FACILITY OPERATION CONDITIONS – Distillate Hydrotreating Unit

Facility Description [326 IAC 2-7-5(15)]:

(ll) The Distillate Hydrotreating (DHT) Unit, identified as Unit ID 720 and rated at 45,000 barrels per day, which removes sulfur from petroleum distillates. Distillate feed is mixed with hydrogen, heated in a process furnace and passed over a catalyst bed to convert sulfur compounds to H_2S. The DHT Unit was constructed in 2005/2006 and includes the following emission units:

(1) DHT Unit Heater B-601, rated at 20 MMBtu per hour and constructed in May 2005. **As part of the CXHO Project, DHT Unit Heater B-601 will be replaced with a 41.9 MMBtu per hour natural gas fired heater, identified as B-601A.** NO_X emissions are controlled by ultra low-NO_X burners having an emission rate of 0.04 pounds per million Btu heat input or less. Emissions are exhausted to a stack identified as 720-01.

(2) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

The DHT Unit shares the DDU Flare, used to control VOC emissions during emergency situations, unit startups and shutdowns.
(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.37.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from Heater B-601 **(until shutdown) and B-601A** shall not exceed 0.03 grains per dry standard cubic foot.

D.37.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7-4.1-1]

Pursuant to 326 IAC IAC 7-4.1-1, the Permittee shall burn only natural gas in DHT Heater B-601 **(until shutdown) and B-601A**.

D.37.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for heater B-601A:

(a) The emissions of NOx shall not exceed 7.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(b) The emissions of CO shall not exceed 7.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(c) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(d) The emissions of PM and PM-10 shall not exceed 0.0019 and 0.0075 pounds per million BTU, respectively.

(e) The firing rate shall not exceed 367,044 million BTU per 12 consecutive month period, with compliance determined at the end of each month.

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.37.~~3~~**4** Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP)[326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC]{40 CFR 60, Subpart GGG]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.4, and E.13 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.37.4**5** Wastewater / Waste Streams [326 IAC 20-16-1][40 CFR 63, Subpart CC][326 IAC 14][40 CFR 61, Subpart FF] [40 CFR 60, Subpart QQQ]

(a) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF, the Permittee shall comply with the requirements specified in Sections E.1 and E.3 for individual drain systems, oil water separators, and aggregate facilities subject to 40 CFR 63, Subpart CC wastewater requirements and 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall comply with the requirements specified in Section E.6 for individual drain systems, oil-water separators, and aggregate facilities subject to 40 CFR 60, Subpart QQQ.

(c) Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream that is managed in a piece of equipment subject to both 40 CFR 63, subpart CC and 40 CFR 60, subpart QQQ is required to comply with only the provisions of 40 CFR 63, Subpart CC specified in Section E.1.

~~D.37.5 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR 63 Subpart DDDDD]~~

~~Pursuant to 40 CFR 63, Subpart DDDDD, the Permittee shall comply with the requirements in Section E.20 for the DHT Heater B-601, which comprises the affected source for new large natural gas fired process heaters.~~

D.37.6 Emission Offset [326 IAC 2-3]

(a) Equipment leaks shall comply with the standards in 40 CFR 60 Subpart GGG and 40 CFR 63 Subpart CC, as applicable for components in gas/vapor service and light liquid service, except that a more stringent definition of a leak shall apply to valves and flanges. An instrument reading of 500 parts per million (ppm) or greater shall constitute a leak for valves and flanges.

(b) All emissions from pressure relief devices and compressor seal systems shall be vented to a flare and burned as fuel.

(c) Nitrogen oxide emissions from Process Heater B-601 shall be controlled by ultra low-NO_X burners having an emission rate of 0.04 pounds per million Btu heat input or less.

The requirements in paragraphs (a) through (c) of this condition render the requirements of Emission Offset (326 IAC 2-3) not applicable.

Compliance Determination Requirements

D.37.7 Testing Requirements [326 IAC 2-7-6(1),(6)][326 IAC 2-1.1-11]

~~(a) No later than 180 days after startup of Heater B-601, the Permittee shall conduct performance tests for carbon monoxide according to Table 5 of 40 CFR 63, Subpart DDDDD. Compliance shall be based on a 3-run average. This performance test shall be repeated annually between 10 and 12 months after the date on which previous performance test was performed.~~

~~(b) Within 60 days after achieving the maximum production rate at which the DHT Unit will be operated, but no later than 180 days after startup of Heater B-601, the Permittee shall conduct performance tests for nitrogen oxide emissions and furnish the Commissioner a written report of the results of such performance tests.~~

~~(c)~~**(a)** Compressors in hydrogen service are exempt from the requirements of 40 CFR 60.592 and 40 CFR 63.698(a) and (c) if the Permittee demonstrates that a compressor is in hydrogen service. The Permittee may use engineering judgment to demonstrate that the percent hydrogen content exceeds 50 percent by volume. In the event that OAQ does not agree, OAQ reserves the right to require testing in accordance with 40 CFR 60.593(b)(1) and 40 CFR 63.698(g)(2)(i)(A).

(b) Compliance with the limits in Condition D.37.3(c) and (d) shall be demonstrated as specified in Condition D.0.3.

D.37.8 Continuous Emissions Monitoring

The CO and NOx Continuous Emissions Monitors (CEMs) for heater B-601A shall be calibrated, maintained, and operated for determining compliance with CO and NOx emissions limits for the heater B-601a in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.37.9 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.37.10 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.37.4(a)** ~~D.37.3(a)~~, the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Condition **D.37.4(b)** ~~D.37.3(b)~~, the Permittee shall keep records as specified in Sections E.1, E.4, and E.13.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.37.5(a)** ~~D.37.4(a)~~, the Permittee shall keep records as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.37.5(b)** ~~D.37.4(b)~~, the Permittee shall keep records as specified in Section E.6.

~~(e) Pursuant to 40 CFR 63, Subpart DDDDD and to document compliance with Condition D.37.5, the Permittee shall keep records as specified in Section E.20.~~

(e) In order to demonstrate compliance with Condition D.37.3, the Permittee shall maintain records of the monthly firing rates at B-601A.

(f) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.37.8, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.37.11 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition **D.37.4(a)** ~~D.37.3(a)~~, the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(b) Pursuant to 40 CFR 60, Subpart GGG, 40 CFR 63, Subpart CC, and to document compliance with Conditions **D.37.6(b)** ~~D.37.5(b)~~, the Permittee shall submit reports as specified in Section E.1, E.4, and E.13.

(c) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 61, Subpart FF and to document compliance with Condition **D.37.5(a)** ~~D.37.4(a)~~, the Permittee shall submit reports as specified in Sections E.1 and E.3.

(d) Pursuant to 40 CFR 60, Subpart QQQ and to document compliance with Condition **D.37.5(b)** ~~D.37.4(b)~~, the Permittee shall submit reports as specified in Section E.6.

~~(e) Pursuant to 40 CFR 63, Subpart DDDDD and to document compliance with Condition D.37.5, the Permittee shall submit reports as specified in Section E.20.~~

(e) **In order to demonstrate compliance with Condition D.37.3, the Permittee shall submit a quarterly summary of the monthly firing rates at heater B-601A to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).**

(f) Pursuant to 326 IAC 3-5-7 and t**o document compliance with Conditions D.37.3 and D.37.8, the Permittee shall submit reports of excess CO and NOx emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:**

(1) **Monitored facility operation time during the reporting period,**
(2) **Date of excess emissions,**
(3) **Time of commencement and completion for each excess emission,**
(4) **Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.**
(5) **A summary itemizing the exceedances by cause.**
(6) **Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:**
(A) **Date of downtime.**
(B) **Time of commencement.**
(C) **Duration of each downtime.**
(D) **Reasons for each downtime.**
(E) **Nature of system repairs and adjustments**

SECTION D.42 FACILITY OPERATION CONDITIONS – Gas Oil Hydrotreating Unit

Facility Description [326 IAC 2-7-5(15)]

(nn) The Gas Oil Hydrotreater (GOHT) Unit, identified as Unit ID 802 and rated at 120,000 barrels per day. The GOHT reduces the sulfur and nitrogen content of the FCU feed and improves the hydrogen content. Operation of the GOHT will enable the FCU to meet gasoline sulfur specifications and to improve FCU conversion yields. The GOHT Unit will be constructed as part of the CXHO Project and includes the following emission units:

(1) Process heaters comprising of:

Heater Identification	Maximum Heat Input Capacity (mmBTU/hr)	Stack Exhausted To	Emissions Controls
F-901A	47	802-01	Ultra low-NOx burners
F-901B	47	802-02	Ultra low-NOx burners

(2) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves, flanges or other connectors, and instrumentation systems.

(3) The GOHT Unit vents to the GOHT Flare (included in Section D.35), used to control VOC emissions during emergency situations, unit startups and shutdowns.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.42.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from each of the stacks 802-01 and 802-02 shall not exceed 0.03 grains per dry standard cubic foot.

D.42.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for the heaters identified as F-901A and F-901B:

(a) The emissions of NOx shall not exceed 0.04 pounds per million BTU.

(b) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(c) The emissions of SO2 shall not exceed 2.3 tons per 12 consecutive month period for each of the heaters F-901A and F-901B, with compliance determined at the end of each month.

(d) The emissions of PM and PM-10 each shall not exceed 0.0019 and 0.0075 pounds per million BTU of fuel burned, respectively.

(e) The emissions of CO shall not exceed 0.02 pounds per million BTU.

(f) The Permittee shall comply with the following fuel usage limits:

Unit ID	Firing rate limit (10^3 mmBTU) per 12 consecutive month period
F-901A	411.72
F-901B	411.72

Compliance with the limits on the annual firing rates and the NOx, VOC, SO2, CO, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions, for NOx, VOC, SO2, CO, PM and PM-10 for the CXHO project remain below the significant levels at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.42.3 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [40 CFR 60, Subpart VV](40 CFR 60, Subpart GGGa)

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 60, Subpart VV, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of VOCs and HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems located at GOHT unit, identified as Unit ID 802.

(c) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.42.4 Fuel Gas Hydrogen Sulfide (H2S) [326 IAC 12][40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for process heaters F-901A and F-901B and the GOHT flare.

Compliance Determination Requirements

D.42.5 Operating Requirement

(a) In order to demonstrate compliance with Condition D.42.3(a), the heaters F-901A and F-901B shall operate using only ultra low-NOx burners.

(b) Compliance with the limits in Condition D.42.2(a), (b), (d) and (e) shall be demonstrated as specified in Condition D.0.3.

D.42.6 Continuous Emissions Monitoring

The Total Reduced Sulfur continuous emission monitoring system (CEMS) shall be calibrated, maintained, and operated for determining compliance with SO2 emissions limits for F-901A and F-901B in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment. The SO2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO2.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.42.7 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.42.8 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall keep records as specified in the LDAR plan.

(b) In order to demonstrate compliance with Condition D.42.2, the Permittee shall maintain the records of monthly firing rates and SO2 emissions at F-901A and F-901B.

(c) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.42.6, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.42.9 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(b) In order to demonstrate compliance with Condition D.42.2, the Permittee shall submit a quarterly summary of the monthly firing rates and SO2 emissions for heaters F-901A and F-901B to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) Pursuant to 326 IAC 3-5-7 and t**o document compliance with Conditions D.42.2 and D.42.6, the Permittee shall submit reports of excess SO2 emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:**

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.43 FACILITY OPERATION CONDITIONS – New Hydrogen Unit

Facility Description [326 IAC 2-7-5(15)]

(oo) The New Hydrogen (New HU) unit, identified as Unit ID 801 commissioned as part of the CXHO Project, produces 99+% pure hydrogen needed for the refinery hydrotreating processes. The New HU produces high purity hydrogen by reacting steam with methane. The reaction is carried out by heating the mixture in a furnace and reacting it in the presence of a catalyst. The New HU heaters HU-1 and HU-2 are equipped with Selective Catalytic Reduction (SCR) for control of NOx. The New HU heater stacks have continuous emissions monitors (CEMS) for NOx and CO. The New HU includes the following sources of emissions and may include insignificant activities listed in Section A.4 of this permit:

(1) Process heaters comprising:

Heater Identification	Maximum Heat Input Capacity (mmBTU/hr)	Stack Exhausted To	Emissions Controls
HU-1	920*	801-01	Low-NO_X burners and selective catalytic reduction
HU-2	920*	801-02	Low-NO_X burners and selective catalytic reduction

*** HU Heaters HU-1 and HU-2 combust both natural gas and PSA offgas with a fuel ratio of no more than 25% natural gas and the remainder PSA offgas.**

(2) One cooling tower (HU Cooling Tower) rated at 14,000 gallons per minute recirculation rate controlled by high efficiency drift eliminators.

(3) The new Hydrogen Unit is connected to the HU Flare system. The system is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The HU Flare will be operated with a water seal or nitrogen purge. As such, there will be no purge gas emissions from the HU Flare. The HU Flare exhausts to S/V 801-03.

(4) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves, flanges or other connectors, and instrumentation systems.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.43.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2 (formerly 326 IAC 6-1-2), particulate matter emissions from each of the stacks 801-01 and 801-02 shall not exceed 0.03 grains per dry standard cubic foot.

D.43.2 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-5] and Emission Offset [326 IAC 2-3]

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

For each of the two (2) heaters HU-1 and HU-2:

(a) The emissions of NOx from each heater shall not exceed 52.4 tons per 12 consecutive month period, with compliance determined at the end of each month.

(c) The emissions of VOC shall not exceed 0.0034 pounds per million BTU.

(d) The emissions of SO2 from each heater shall not exceed 0.0006 pounds per million BTU.

(e) The emissions of PM and PM-10 each shall not exceed 0.0068 pounds per million BTU.

(f) The emissions of CO shall not exceed 60.4 tons per 12 consecutive month period, with compliance determined at the end of each month.

(g) The Permittee shall comply with the following fuel usage limits:

Unit ID	Natural gas firing rate limit (10^3 mmBTU) per 12 consecutive month period	Total Gas gas firing rate limit (10^3 mmBTU) per 12 consecutive month period
HU-1	2014.8	8059.2
HU-2	2014.8	8059.2

For the HU flare pilot gas:

(h) The emissions of NOx shall not exceed 100 pounds per million cubic feet of fuel burned.

(i) The emissions of VOC shall not exceed 5.5 pounds per million cubic feet of fuel burned.

(j) The emissions of SO2 shall not exceed 0.6 pounds per million cubic feet of fuel burned.

(k) The emissions of PM and PM-10 shall not exceed 1.9 and 7.6 pounds per million cubic feet of fuel burned, respectively.

(l) The pilot gas used at the HU flare shall be limited to 2,233,800 cubic feet per 12 consecutive month period.

For the HU cooling tower:

(m) The average concentration of total dissolved solids (TDS) in the water input to HU Cooling Tower shall not exceed an average annual concentration of 6300 mg/L per 12 consecutive month period.

(n) The emissions of PM and PM-10 from HU Cooling tower shall not exceed 0.42 pounds per hour.

Compliance with the firing rate limits and the NOx, VOC, CO, SO2, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions for NOx, VOC, CO, SO2, PM and PM-10 for the CXHO project remain below the significant thresholds at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.43.3 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAP) [326 IAC 8-4-8] [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC and 40 CFR 60, Subpart VV, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of VOCs and HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems located at GOHT unit, identified as Unit ID 802.

(c) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.43.4 Fuel Gas Hydrogen Sulfide (H2S) [326 IAC 12][40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for process heaters HU-1 and HU-2 and the HU flare.

D.43.5 Standards for Miscellaneous Process Vents [326 IAC 20-16-1] [40 CFR 63, Subpart CC]

Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Section E.1 for the New HU flare relating to the control of process vents.

D.43.6 Equipment Leaks of VOC [326 IAC 12] [40 CFR 60, Subpart GGG]

Pursuant to 40 CFR 60, Subpart GGG, the Permittee shall comply with the control device standards specified in Section E.13 for the New HU flare.

D.43.7 Fuel Gas Hydrogen Sulfide (H2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60, Subpart J, the Permittee shall comply with the applicable requirements specified in Section E.2 for the New HU Flare.

Compliance Determination Requirements

D.43.8 Operating Requirement

(a) In order to demonstrate compliance with Condition D.43.2, the Permittee shall operate the heaters HU-1 and HU-2 using only low-NOx burners.

(b) In order to comply with Condition D.43.2, the SCRs shall be operated as necessary to meet the NOx emissions limits for heaters HU-1 and HU-2.

(c) In order to comply with Condition D.43.2, the liquid drift eliminator shall be in operation and control PM and PM-10 emissions from the HU Cooling Tower at all times that HU Cooling Tower is in operation.

(d) Compliance with the limits in Condition D.43.2 shall be demonstrated as specified in Condition D.0.3.

D.43.9 Continuous Emissions Monitoring

The CO and NOx continuous emission monitoring systems (CEMS) for HU-1 and HU-2 shall be calibrated, maintained, and operated for determining compliance with CO and NOx emissions limits for HU-1 and HU-2 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.43.10 Compliance Monitoring Requirements [326 IAC 2-3]

To monitor compliance with Condition D.43.2 the Permittee shall take weekly measurements of the total dissolved solids (TDS) in the water input to HU Cooling Tower. If the TDS limitation is exceeded, the Permittee shall perform quantitative water analyses and shall take the remedial action necessary to correct the problem.

D.43.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.43.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall keep records as specified in the LDAR plan.

(b) In order to demonstrate compliance with Condition D.43.2, the Permittee shall maintain the records of monthly firing rates using natural gas and PSA tailgas and CO, NOx and SO2 emissions at HU-1 and HU-2.

(c) In order to demonstrate compliance with Condition D.43.2, the Permittee shall maintain the records of monthly firing rates using pilot gas at the HU flare.

(d) To document compliance with Condition D.43.2, the Permittee shall maintain records of the total dissolved solids (TDS) in the water input to HU Cooling Tower and any remedial actions taken (including the date remedial actions were initiated).

(e) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.43.9, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.43.13 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(b) In order to demonstrate compliance with Condition D.43.2, the Permittee shall submit a quarterly summary of the fuel usages at heaters HU-1, HU-2 and HU flare and CO, NOx, and SO2 emissions for HU-1 and HU-2 to the address listed in Section C - General Reporting Requirements within thirty (30) days after the end of the quarter being reported. The quarterly report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.43.2 and D.43.9, the Permittee shall submit reports of excess SO2, CO, and NOx emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.44 FACILITY OPERATION CONDITIONS – New Boilers

Facility Description [326 IAC 2-7-5(15)]

(oo) Two (2) new boilers, identified as New Boiler 1 and New Boiler 2, per SPM 089-25488-00453, each rated at 580 million BTU per hour, equipped with low-NOx burners and/or Selective Catalytic Reduction (SCR) for control of NOx, using either blended natural gas and refinery gas or only refinery fuel gas. A separate TRS CEMS shall be installed to measure the sulfur content of the fuel gas or fuel gas-natural gas blend fed to New Boiler 1 and New Boiler 2.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.44.1 Particulate Matter Emissions - Lake County [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2(b)(3), the particulate matter emissions from New Boiler 1 and New Boiler 2 shall be no greater than one-hundredth (0.01) grain per dry standard cubic foot (dscf).

D.44.2 SO2 Emissions Limitation

The SO2 emissions from each of the boilers identified as New Boiler 1 and New Boiler 2 hall be limited to less than 25 tons per 12 consecutive month period.

Compliance with this limit shall render the requirements of 326 IAC 7-4.1-1 (Lake County SO2 Emissions Limitations) not applicable.

D.44.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) The firing rate (total) at New Boiler 1 and New Boiler 2 shall not exceed 9,907,560 mmBTU per 12 consecutive month period, with compliance determined at the end of each month.

(b) The emissions of NOx (total) from the boilers shall not exceed 322.0 tons per 12 consecutive month period, with compliance determined at the end of each month.

(c) The emissions of SO2 from each of the boilers shall not exceed 24.9 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) The emissions of CO (total) shall not exceed 118.9 tons per 12 consecutive month period, with compliance determined at the end of each month.

(e) The emissions of PM and PM-10 each shall not exceed 0.002 and 0.007 pounds per million BTU, respectively.

(f) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

Compliance with the firing rate limits and the NOx, VOC, CO, SO2, PM and PM-10 emissions limits, in conjunction with the emissions limits at other units at this source, shall ensure that the net emissions increases, including fugitive emissions for NOx, VOC, CO, SO2, PM and PM-10 for the CXHO project remain below the significant thresholds at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants.

D.44.4 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60.104(a)(1), the Permittee shall comply with the requirements specified in Section E.2 for New Boiler 1 and New Boiler 2.

D.44.5 Equipment Leaks of Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs) [326 IAC 20-16-1] [40 CFR 63, Subpart CC] [326 IAC 8-4-8] [40 CFR 60, Subpart GGGa]

(a) Pursuant to 326 IAC 8-4-8, the Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee. The Permittee shall update the LDAR Plan as necessary and shall submit a copy of the revised LDAR Plan to IDEM OAQ for approval. If IDEM, OAQ determines that the procedures specified in the LDAR Plan will not demonstrate compliance with the fugitive emission limitations, IDEM, OAQ may require the Permittee to revise the plan.

(b) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1 and E.4 for equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, and instrumentation systems.

(c) Pursuant to 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC, the Permittee shall comply with the requirements specified in Sections E.1, E.25, and E.26 for equipment leaks of VOC and HAP from compressors and each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

D.44.6 Fuel Gas Hydrogen Sulfide (H_2S) [326 IAC 12] [40 CFR 60, Subpart J]

Pursuant to 40 CFR 60, Subpart J, the Permittee shall comply with the requirements specified in Section E.2 for New Boiler 1 and New Boiler 2.

D.44.7 Standards of Performance for Boilers [40 CFR Part 60, Subpart Db] [326 IAC 12]

Pursuant to 40 CFR 60, Subpart Db, the Permittee shall comply with the requirements of Section E.22 for the New Boiler 1 and New Boiler 2.

Compliance Determination Requirements

D.44.8 Operating Requirement

In order to demonstrate compliance with D.44.3, fuel oil shall not be used as fuel for New Boiler 1 and New Boiler 2.

D.44.9 Continuous Emissions Monitoring

The Total Reduced Sulfur, CO and NOx continuous emission monitoring systems (CEMS) for New Boiler 1 and New Boiler 2 shall be calibrated, maintained, and operated for determining compliance with SO2, CO and NOx emissions limits for New Boiler 1 and New Boiler 2 in accordance with the applicable requirements in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment and Condition C.13- Maintenance of Emission Monitoring Equipment.

D.44.10 Requirement to Submit a Significant Permit Modification Application [326 IAC 2-7-12] [326 IAC 2-7-5]

In the event that New Boiler 1 and New Boiler 2 are constructed prior to 2009, the NOx authorized account representative shall submit an application for a significant permit modification to IDEM, OAQ requesting the incorporation of NOx Budget Permit requirements for New Boiler 1 and New Boiler 2 under 326 IAC 10-4 into the Title V permit.

(a) The significant permit modification application shall be consistent with 326 IAC 2-7-12, including information sufficient for IDEM, OAQ to incorporate into the Title V permit the applicable requirements of 326 IAC 10-4, a description of the affected source and activities subject to the requirements, and a description of how the Permittee will meet the applicable requirements.

(b) For any source, with one (1) or more NO_x budget units that commences operation on or after January 1, 2001, the NO_x authorized account representative shall submit a complete NO_x budget permit application covering each NO_x budget unit at least two hundred seventy (270) days before the date on which the NO_x budget unit commences operation.

(c) The significant permit modification application shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53, IGCN 1003
Indianapolis, Indiana 46204-2251

Compliance Monitoring Requirements

D.44.11 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.44.12 Record Keeping Requirements

(a) In order to document compliance with Conditions D.44.3 and D.44.6, the Permittee shall maintain a daily record of the following for New Boiler 1 and New Boiler 2:

(1) operational status of each facility,

(2) fuel type,

(3) average daily sulfur content for each fuel type,

(4) average daily fuel gravity for each fuel type,

(5) total daily fuel usage for each type, and

(6) heat content of each fuel type.

(c) Pursuant to 40 CFR 60, Subpart J, the Permittee shall maintain the records specified in Section E.2.

(d) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.44.5, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall keep records as specified in Sections E.1 and E.4.

(f) Pursuant to 40 CFR 60, Subpart Db, the Permittee shall keep records as specified in Section E.22.

(h) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall keep records as specified in Section E.6.

(i) In order to demonstrate compliance with Condition D.44.3, the Permittee shall maintain the records of monthly firing rates and CO, NOx, and SO2 emissions at New Boiler 1 and New Boiler 2.

(j) Pursuant to 326 IAC 3-5-6 and to document compliance with Condition D.44.9, the Permittee shall keep the following records for the continuous emission monitors:

(1) One-minute block averages.

(2) All documentation relating to:

(A) design, installation, and testing of all elements of the monitoring system, and

(B) required corrective action or compliance plan activities.

(3) All maintenance logs, calibration checks, and other required quality assurance activities,

(4) All records of corrective and preventive action, and

(5) A log of plant operations, including the following:

(A) Date of facility downtime,

(B) Time of commencement and completion of downtime, and

(C) Reason for each downtime.

D.44.13 Reporting Requirements

(a) Pursuant to 40 CFR 60, Subpart J, the Permittee shall submit to IDEM, OAQ the reports specified in Section E.2.

(b) Pursuant to 326 IAC 8-4-8 and to document compliance with Condition D.44.5, the Permittee shall submit reports as specified in the LDAR plan.

(c) Pursuant to 40 CFR 63, Subpart CC, the Permittee shall submit reports as specified in Sections E.1 and E.4.

(d) Pursuant to 40 CFR 60, Subpart QQQ, the Permittee shall submit reports as specified in Section E.6.

(e) Pursuant to 40 CFR 60, Subpart Db, the Permittee shall submit reports as specified in Section E.22.

() Pursuant to 326 IAC 3-5-7 and to document compliance with Conditions D.44.3 and D44.9, the Permittee shall submit reports of excess SO2, NOx and CO emissions within thirty (30) days of the end of each quarter in which the excess emissions occur. The reports shall include the following:

(1) Monitored facility operation time during the reporting period,
(2) Date of excess emissions,
(3) Time of commencement and completion for each excess emission,
(4) Magnitude of each excess emission. For gaseous emissions, the excess emissions, in units of the applicable standard, must be reported based on the applicable averaging time, for example, one (1) hour block, three (3) hour block, three (3) hour rolling, in addition to any other reporting requirements that may be applicable.
(5) A summary itemizing the exceedances by cause.
(6) Continuous Monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(A) Date of downtime.
(B) Time of commencement.
(C) Duration of each downtime.
(D) Reasons for each downtime.
(E) Nature of system repairs and adjustments

SECTION D.45 FACILITY OPERATION CONDITIONS – Firepump Engines and Concrete Crusher

Facility Description [326 IAC 2-7-5(15)]

Insignificant Activity:

(ff) Three (3) emergency firepump engines, identified as Firepump 1, 2 and 3, per SPM 089-25488-00453, each rated at 390 HP.

(gg) One (1) concrete crushing process, per SPM 089-25488-00453, with a maximum processing capacity of 120 tons per hour, having two (2) transfer points.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.45.1 Particulate Matter Emissions - Lake County [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2(a), the particulate matter emissions from Firepump 1, Firepump 2, Firepump 3 and the concrete crushing operation shall not exceed 0.03 gr/dscf.

D.45.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-5] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-5, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) The total hours of operation for the three firepump engines shall not exceed 500 hours per year.

(b) The total amount of concrete processed by the concrete crusher shall not exceed 18,000 tons.

Compliance with the emissions limits at the three firepumps and the other units at this source, shall ensure that the net emissions increases, including fugitive emissions for NOx, VOC, CO, SO2, PM and PM-10 for the CXHO project remain below the significant thresholds at each stage of the phased construction of the CXHO project, rendering 326 IAC 2-2, 326 IAC 2-1.1-5 and 326 IAC 2-3 not applicable for these pollutants. comply with the requirements specified in Section E.2 for New Boiler 1 and New Boiler 2.

D.45.3 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60, Subpart IIII] [326 IAC 12]

Pursuant to 40 CFR 60, Subpart IIII, the Permittee shall comply with the requirements of Section E.23 for emergency generators and emergency fire pumps.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.45.4 Record Keeping Requirements

Pursuant to 40 CFR 60, Subpart IIII, the Permittee shall keep records as specified in Section E.23.

D.45.5 Reporting Requirements

Pursuant to 40 CFR 60, Subpart IIII, the Permittee shall submit reports as specified in Section E.23.

SECTION E.20 40 CFR Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants For Industrial, Commercial, and Institutional Boilers and Process Heaters

[RESERVED]

~~E.20.1 General Provisions Relating to NESHAP Subpart DDDDD [40 CFR Part 63, Subpart DDDDD] [326 IAC 20-1]~~

~~Pursuant to 40 CFR 63.7565, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, as specified in Table 10 of 40 CFR Part 63, Subpart DDDDD in accordance with the schedule in 40 CFR Part 63, Subpart DDDDD.~~

~~E.20.2 NESHAP Subpart DDDDD Requirements [40 CFR Part 63, Subpart DDDDD]~~

~~Pursuant to 40 CFR 63.7485 and 63.7490, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart DDDDD listed in this condition for the emission units listed in paragraphs (a), (b), and (c):~~

~~(a) The following emission units meet the definition of existing units in the large gaseous fuel subcategory:~~

~~(1) H-1X, H-2, H-3, H-200, and H-300 process heaters located at No.11A and 11C Pipe Stills (Section D.1).~~

~~(2) H-101, H-102, H-103, and H-104 process heaters located at the No.11B Coker (Section D.2).~~

~~(3) H-1AN, H-1AS, H-1B, H-2, H-1CN, and H-1CX process heaters located at the No.12 Pipe Still (Section D.3).~~

~~(4) H-1 process heaters located at the Isomerization Unit (Section D.9).~~

~~(5) F-200A and F-200B process heaters located at the ARU (Section D.10).~~

~~(6) F-401 process heater located at the Blending Oil Unit (Section D.11).~~

~~(7) H-1, H-2, and F-7 process heaters located at the No. 3 Ultraformer (Section D.15).~~

~~(8) F-1, F-8A, F-8B, F-2, F-3, F-4R, F-5, F-6, and F-7 process heaters located at the No.4 Ultraformer (Section D.16).~~

~~(9) B-501 process heater at the Hydrogen Unit (Section D.17).~~

~~(10) WB-301 and WB-302 process heaters located at the DDU (Section D.18).~~

~~(11) F-801A/B and F-801C process heaters located at the Cat Feed Hydrotreating Unit (Section D.19).~~

~~(12) F-101 and F-102A process heaters located at the Catalytic Refining Unit (CRU) (Section D.20).~~

~~(13) #3, #4, #5, #6, and #7 boilers located at the No.1 Stanolind Power Station (Section D.23).~~

~~(14) #1, #2, #3, #4, and #6 boilers located at the No.3 Stanolind Power Station (Section D.24).~~

~~(15) F-1 and F-2 process heaters located at the Asphalt Facility (Section D.32).~~

~~(b) The following emission units meet the definition of existing units in the small gaseous fuel subcategory:~~

~~(1) Marine Dock Heater F-100 (Section D.34).~~

~~(2) Kewanee Boilers #1 and #2 (Section D.40).~~

~~(c) The following emission unit meets the definition of a new unit in the large gaseous fuel subcategory: DHT B-601 process heater located at the Distillate Hydrotreating Unit (Section D.37)~~

~~Subpart DDDDD- National Emission Standards for Hazardous Air Pollutants for Industrial Commercial, and Institutional Boilers and Process Heaters~~

~~§63.7480 What is the purpose of this subpart?~~

~~This subpart establishes national emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards.~~

~~§63.7485 Am I subject to this subpart?~~

~~You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP as defined in §63.2 or §63.761 (40 CFR Part 63, Subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in §63.7491.~~

~~§63.7490 What is the affected source of this subpart?~~

~~(a) This subpart applies to new, reconstructed, or existing affected sources as described in paragraphs (a)(1) and (2) of this section.~~

~~(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory located at a major source as defined in §63.7575.~~

~~(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source as defined in §63.7575.~~

~~(b) A boiler or process heater is new if you commence construction of the boiler or process heater after January 13, 2003, and you meet the applicability criteria at the time you commence construction.~~

~~(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in §63.2, you commence reconstruction after January 13, 2003, and you meet the applicability criteria at the time you commence reconstruction.~~

~~(d) A boiler or process heater is existing if it is not new or reconstructed.~~

~~§63.7491 Are any boilers or process heaters not subject to this subpart?~~

~~The types of boilers and process heaters listed in paragraphs (a) through (o) of this section are not subject to this subpart.~~

~~(h) A hot water heater as defined in this subpart.~~

~~(n) Temporary boilers as defined in this subpart.~~

~~§63.7495 When do I have to comply with this subpart?~~

~~(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by November 12, 2004 or upon startup of your boiler or process heater, whichever is later.~~

~~(b) If you have an existing boiler or process heater, you must comply with this subpart no later than September 13, 2007.~~

~~(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.~~

~~§63.7499 What are the subcategories of boilers and process heaters?~~

~~The subcategories of boilers and process heaters are large solid fuel, limited use solid fuel, small solid fuel, large liquid fuel, limited use liquid fuel, small liquid fuel, large gaseous fuel, limited use gaseous fuel, and small gaseous fuel. Each subcategory is defined in §63.7575.~~

~~§63.7500 What emission limits, work practice standards, and operating limits must I meet?~~

~~(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section.~~

~~(1) You must meet each emission limit and work practice standard in Table 1 to this subpart that applies to your boiler or process heater, except as provided under §63.7507.~~

~~§63.7505 What are my general requirements for complying with this subpart?~~

~~(a) You must be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.~~

~~(b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in §63.6(e)(1)(i).~~

~~(e) If you have an applicable emission limit or work practice standard, you must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).~~

~~§63.7506 Do any boilers or process heaters have limited requirements?~~

~~(b) The affected boilers and process heaters listed in paragraphs (b)(1) through (3) of this section are subject to only the initial notification requirements in §63.9(b) (i.e., they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSMP, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart or any other requirements in subpart A of this part).~~

~~(1) Existing large and limited use gaseous fuel units.~~

~~(c) The affected boilers and process heaters listed in paragraphs (c)(1) through (4) of this section are not subject to the initial notification requirements in §63.9(b) and are not subject to any requirements in this subpart or in subpart A of this part (i.e., they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSM plans, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart, or any other requirements in subpart A of this part.~~

~~(3) Existing small gaseous fuel boilers and process heaters.~~

~~§63.7510 What are my initial compliance requirements and by what date must I conduct them?~~

~~(a) For affected sources that elect to demonstrate compliance with any of the emission limits of this subpart through performance testing, your initial compliance requirements include conducting performance tests according to §63.7520 and Table 5 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart, establishing operating limits according to §63.7530 and Table 7 to this subpart, and conducting CMS performance evaluations according to §63.7525.~~

~~(c) For affected sources that have an applicable work practice standard, your initial compliance requirements depend on the subcategory and rated capacity of your boiler or process heater. If your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, your initial compliance demonstration is conducting a performance test for carbon monoxide according to Table 5 to this subpart. If your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, your initial compliance demonstration is conducting a performance evaluation of your continuous emission monitoring system for carbon monoxide according to §63.7525(a).~~

~~(d) For existing affected sources, you must demonstrate initial compliance no later than 180 days after the compliance date that is specified for your source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart.~~

~~(g) If your new or reconstructed affected source commences construction or reconstruction after November 12, 2004, you must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the source.~~

~~§63.7515 When must I conduct subsequent performance tests or fuel analyses?~~

~~(a) You must conduct all applicable performance tests according to §63.7520 on an annual basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.~~

~~(e) If you have an applicable work practice standard for carbon monoxide and your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, you must conduct annual performance tests for carbon monoxide according to §63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.~~

~~(g) You must report the results of performance tests and fuel analyses within 60 days after the completion of the performance tests or fuel analyses. This report should also verify that the operating limits for your affected source have not changed or provide documentation of revised operating parameters established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests and fuel analyses should include all applicable information required in §63.7550.~~

~~§63.7520 What performance tests and procedures must I use?~~

~~(a) You must conduct all performance tests according to §63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in §63.7(c) if you elect to demonstrate compliance through performance testing.~~

~~(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.~~

~~(c) You may not conduct performance tests during periods of startup, shutdown, or malfunction.~~

~~(f) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.~~

~~§63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?~~

~~(a) You must demonstrate initial compliance with each emission limit and work practice standard that applies to you by either conducting initial performance tests and establishing operating limits, as applicable, according to §63.7520, paragraph (c) of this section, and Tables 5 and 7 to this subpart OR conducting initial fuel analyses to determine emission rates and establishing operating limits, as applicable, according to §63.7521, paragraph (d) of this section, and Tables 6 and 8 to this subpart.~~

~~(e) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).~~

~~§63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?~~

~~(b) You must report each instance in which you did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply to you. You must also report each instance during a startup, shutdown, or malfunction when you did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7550.~~

~~(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with the SSMP as required in §63.7505(e).~~

~~(d) Consistent with §§63.6(e)and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the EPA Administrator's satisfaction that you were operating in accordance with your SSMP. The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).~~

~~§63.7545 What notifications must I submit and when?~~

~~(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.~~

~~(b) As specified in §63.9(b)(2), if you startup your affected source before November 12, 2004, you must submit an Initial Notification not later than 120 days after November 12, 2004. The Initial Notification must include the information required in paragraphs (b)(1) and (2) of this section, as applicable.~~

~~(1) If your affected source has an annual capacity factor of greater than 10 percent, your Initial Notification must include the information required by §63.9(b)(2).~~

~~(c) As specified in §63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after November 12, 2004, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.~~

~~(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.~~

~~(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530(a), you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For each initial compliance demonstration, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (9), as applicable.~~

~~(1) A description of the affected source(s) including identification of which subcategory the source is in, the capacity of the source, a description of the add-on controls used on the source description of the fuel(s) burned, and justification for the fuel(s) burned during the performance test.~~

~~(2) Summary of the results of all performance tests, fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.~~

~~(3) Identification of whether you are complying with the particulate matter emission limit or the alternative total selected metals emission limit.~~

~~(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing or fuel analysis.~~

~~(5) Identification of whether you plan to demonstrate compliance by emissions averaging.~~

~~(6) A signed certification that you have met all applicable emission limits and work practice standards.~~

~~(7) A summary of the carbon monoxide emissions monitoring data and the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable work practice standard in Table 1 to this subpart.~~

~~(8) If your new or reconstructed boiler or process heater is in one of the liquid fuel subcategories and burns only liquid fossil fuels other than residual oil either alone or in combination with gaseous fuels, you must submit a signed statement certifying this in your Notification of Compliance Status report.~~

~~(9) If you had a deviation from any emission limit or work practice standard, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.~~

~~§63.7550 What reports must I submit and when?~~

~~(a) You must submit each report in Table 9 to this subpart that applies to you.~~

~~(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.~~

~~(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495.~~

~~(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.7495.~~

~~(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.~~

~~(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.~~

~~(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.~~

~~(c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of this section.~~

~~(1) Company name and address.~~

~~(2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.~~

~~(3) Date of report and beginning and ending dates of the reporting period.~~

~~(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.~~

~~(5) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.~~

~~(6) A signed statement indicating that you burned no new types of fuel. Or, if you did burn a new type of fuel, you must submit the calculation of chlorine input, using Equation 5 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 9 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of TSM input, using Equation 6 of §63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate using Equation 10 of §63.7530 that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of mercury input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 11 of §63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).~~

~~(7) If you wish to burn a new type of fuel and you can not demonstrate compliance with the maximum chlorine input operating limit using Equation 5 of §63.7530, the maximum TSM input operating limit using Equation 6 of §63.7530, or the maximum mercury input operating limit using Equation 7 of §63.7530, you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.~~

~~(9) If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in §63.10(d)(5)(i).~~

~~(10) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, and there are no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.~~

~~(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 9 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.~~

~~§63.7555 What records must I keep?~~

~~(a) You must keep records according to paragraphs (a)(1) through (3) of this section.~~

~~(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).~~

~~(2) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.~~

~~(3) Records of performance tests, fuel analyses, or other compliance demonstrations, performance evaluations, and opacity observations as required in §63.10(b)(2)(viii).~~

~~§63.7560 In what form and how long must I keep my records?~~

~~(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).~~

~~(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.~~

~~(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.~~

~~§63.7565 What parts of the General Provisions apply to me?~~

~~Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.~~

~~Table 1 to Subpart DDDDD of Part 63—Emission Limits and Work Practice Standards~~

~~As stated in §63.7500, you must comply with the following applicable emission limits and work practice standards:~~

~~If your boiler or process heater is in this subcategory~~	~~For the following pollutants~~	~~You must meet the following emission limits and work practice standards~~
~~7. New or reconstructed large gaseous fuel.~~	~~Carbon Monoxide~~	~~400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).~~

~~Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements~~

~~As stated in §63.7520, you must comply with the following requirements for performance test for existing, new or reconstructed affected sources:~~

~~To conduct a performance test for the following pollutant~~	~~You must~~	~~Using~~
~~5. Carbon Monoxide~~	~~a. Select the sampling ports location and the number of traverse points.~~	~~Method 1 in appendix A to part 60 of this chapter.~~
	~~b. Determine oxygen and carbon dioxide concentrations of the stack gas.~~	~~Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522-00 (IBR, see §63.14(b)), or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).~~
	~~c. Measure the moisture content of the stack gas.~~	~~Method 4 in appendix A to part 60 of this chapter.~~
	~~d. Measure the carbon monoxide emission concentration.~~	~~Method 10, 10A, or 10B in appendix A to part 60 of this chapter, or ASTM D6522-00 (IBR, see §63.14(b)) when the fuel is natural gas.~~

~~Table 9 to Subpart DDDDD of Part 63—Reporting Requirements~~

~~As stated in §63.7550, you must comply with the following requirements for reports:~~

~~You must submit a(n)~~	~~The report must contain~~	~~You must submit the report~~
~~1. Compliance report~~	~~a. Information required in §63.7550(c)(1) through (11); and~~	~~Semiannually according to the requirements in §63.7550(b).~~
	~~b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and~~	
	~~c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in §63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of- control, as specified in §63.8(c)(7), the report must contain the information in §63.7550(e); and~~	
	~~d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in §63.10(d)(5)(i)~~	
~~2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard.~~	~~a. Actions taken for the event; and~~	~~i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and~~
	~~b. The information in §63.10(d)(5)(ii)~~	~~ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.~~

Section E.21 40 CFR 63, Subpart GGGGG—National Emission Standards for Hazardous Air Pollutants: Site Remediation

E.21.1 General Provisions Relating to NESHAP Subpart GGGGG [40 CFR Part 63, Subpart GGGGG] [326 IAC 20-1]

Pursuant to 40 CFR 63.7955, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, as specified in Table 3 of 40 CFR Part 63, Subpart GGGGG in accordance with the schedule in 40 CFR Part 63, Subpart GGGGG.

E.21.2 NESHAP Subpart GGGGG Requirements [40 CFR Part 63, Subpart GGGGG] [326 IAC 20-87]

~~(a)~~ The affected sources for the site remediation activities, including process vents, remediation material management units, and equipment components described in Section D.28 of this permit, are subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Site Remediation, (40 CFR 63, Subpart GGGGG), effective October 8, 2003. Pursuant to this rule, the Permittee must comply with the provisions of 40 CFR 63, Subpart GGGGG, which are incorporated by reference in 326 IAC 20-87, on and after October 8, 2006. ~~or accept and meet an enforceable HAP emissions limit below the major source threshold prior to October 8, 2006.~~

~~(b) Since the applicable requirements associated with the compliance options are not included and specifically identified in this permit, the permit shield authorized by the B section of this permit in the condition titled Permit Shield, and set out in 326 IAC 2-7-15 does not apply to paragraph (a) of this condition.~~

~~(c) The definitions in 40 CFR 63, Subpart GGGGG, CFR 63.7957 are applicable to the Permittee.~~

~~E.21.3 National Emissions Standards for Hazardous Air Pollutants for Site Remediation - Notification Requirements [40 CFR 63, Subpart GGGGG] [326 IAC 20-87]~~

~~(a) Pursuant to 40 CFR 63.7950, the Permittee shall submit all of the notifications in 40 CFR 63.7(b) and (c), 63.8(e), 63.8(f)(4) and (6), and 63.9(b) through (h) that apply to the affected source and chosen compliance method. These notifications include, but are not limited to, the following:~~

~~(1) A Notification of Compliance Status containing the information required by 40 CFR 63.9(h) in accordance with 40 CFR 63.7950(e). The Notification of Compliance Status must be submitted:~~

~~(A) Before the close of business on the 30th calendar day following completion of the initial compliance demonstration for each initial compliance demonstration that does not include a performance test; and~~

~~(B) Before the close of business on the 60th calendar day following the completion of the performance test according to the requirement specified in 40 CFR 63.10(d)(2) for each initial compliance demonstration that includes a performance test or design evaluation. The Permittee shall submit the complete design evaluation and supporting documentation and the performance test results, as applicable.~~

~~(2) If required to conduct a performance test, a notification of intent to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin as required by 40 CFR 63.7(b)(1) and 40 CFR 63.7950(a) and (d); and~~

~~(3) If required to use a continuous monitoring system (CMS), notifications, if required, as specified in 40 CFR 63.9(g), by the date of submission of the notification of intent to conduct a performance test, as required by 40 CFR 63.7950(a).~~

~~(b) The notifications required by paragraph (a) shall be submitted to:~~

~~Indiana Department of Environmental Management~~
~~Compliance Data Section, Office of Air Quality~~
~~100 North Senate Avenue~~
~~Indianapolis, Indiana 46204-2251~~

~~E.21.4 Requirement to Submit a Significant Permit Modification Application [326 IAC 2-7-12] [326 IAC 2-7-5]~~

~~The Permittee shall submit an application for a significant permit modification to IDEM, OAQ to include information regarding which compliance option or options will be chosen.~~

~~(a) The significant permit modification application shall be consistent with 326 IAC 2-7-12, including information sufficient for IDEM, OAQ to incorporate into the Title V permit the applicable requirements of 40 CFR 63, Subpart GGGGG, a description of the affected source and activities subject to the standard, and a description of how the Permittee will meet the applicable requirements of the standard.~~

~~(b) The significant permit modification application shall be submitted no later than the 60th day following the completion of the performance test and/or initial compliance demonstrations according to 40 CFR 63.10(d)(2).~~

~~(c) The significant permit modification application shall be submitted to:~~

~~Indiana Department of Environmental Management~~
~~Permits Branch, Office of Air Quality~~
~~MC 61-53 IGCN 1003~~
~~100 North Senate Avenue,~~
~~Indianapolis, Indiana 46204-2251~~

What This Subpart Covers
§ 63.7880 What is the purpose of this subpart?

This subpart establishes national emissions limitations and work practice standards for hazardous air pollutants (HAP) emitted from site remediation activities. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emissions limitations and work practice standards.

§ 63.7881 Am I subject to this subpart?

(a) This subpart applies to you if you own or operate a facility at which you conduct a site remediation, as defined in §63.7957; and this site remediation, unless exempted under paragraph (b) or (c) of this section, meets all three of the following conditions specified in paragraphs (a)(1) through (3) of this section.

(1) Your site remediation cleans up a remediation material, as defined in §63.7957.

(2) Your site remediation is co-located at your facility with one or more other stationary sources that emit HAP and meet an affected source definition specified for a source category that is regulated by another subpart under 40 CFR part 63. This condition applies regardless whether or not the affected stationary source(s) at your facility is subject to the standards under the applicable subpart(s).

(3) Your facility is a major source of HAP as defined in §63.2, except as specified in paragraph (a)(3)(i) or (ii) of this section. A major source emits or has the potential to emit any single HAP at the rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year.

(i) For production field facilities, as defined in §63.761, only the HAP emissions from the glycol dehydration units and storage vessels with the potential for flash emissions (both as defined in §63.761) shall be aggregated with the HAP emissions from the site remediation activities at the facility for a major source determination.

(ii) For natural gas transmission and storage facilities, HAP emissions shall be aggregated in accordance with the definition of major source in §63.1271 for a major source determination.

(b) You are not subject to this subpart if your site remediation qualifies for any of one of the exemptions listed in paragraphs (b)(1) through (6) of this section.

(1) Your site remediation is not subject to this subpart if the site remediation only cleans up material that does not contain any of the HAP listed in Table 1 of this subpart.

(2) Your site remediation is not subject to this subpart if the site remediation will be performed under the authority of the Comprehensive Environmental Response and Compensation Liability Act (CERCLA) as a remedial action or a non time-critical removal action.

(3) Your site remediation is not subject to this subpart if the site remediation will be performed under a Resource Conservation and Recovery Act (RCRA) corrective action conducted at a treatment, storage and disposal facility (TSDF) that is either required by your permit issued by either the U.S. Environmental Protection Agency (EPA) or a State program authorized by the EPA under RCRA section 3006; required by orders authorized under RCRA; or required by orders authorized under RCRA section 7003.

(4) Your site remediation is not subject to this subpart if the site remediation is conducted at a gasoline service station to clean up remediation material from a leaking underground storage tank.

(5) Your site remediation is not subject to this subpart if the site remediation is conducted at a farm or residential site.

(6) Your site remediation is not subject to this subpart if the site remediation is conducted at a research and development facility that meets the requirements under Clean Air Act (CAA) section 112(c)(7).

(c) Your site remediation activities are not subject to the requirements of this subpart, except for the recordkeeping requirements in this paragraph, provided that you meet the requirements specified in paragraphs (c)(1) through (c)(3) of this section.

(1) You determine that the total quantity of the HAP listed in Table 1 to this subpart that is contained in the remediation material excavated, extracted, pumped, or otherwise removed during all of the site remediations conducted at your facility is less than 1 megagram (Mg) annually. This exemption applies the 1 Mg limit on a facility-wide, annual basis, and there is no restriction to the number of site remediations that can be conducted during this period.

(2) You must prepare and maintain at your facility written documentation to support your determination that the total HAP quantity in your remediation materials for the year is less than 1 Mg. The documentation must include a description of your methodology and data used for determining the total HAP content of the remediation material.

(3) Your Title V permit does not have to be reopened or revised solely to include the recordkeeping requirement specified in paragraph (c)(2) of this section. However, the requirement must be included in your permit the next time the permit is renewed, reopened, or revised for another reason.

(d) Your site remediation is not subject to the requirements of this subpart if all remediation activities at your facility subject to this subpart are completed and you have notified the Administrator in writing that all remediation activities subject to this subpart are completed. You must maintain records of compliance, in accordance with §63.7953, for each remediation activity that was subject to this subpart. All future remediation activity meeting the applicability criteria in this section must comply with the requirements of this subpart.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69016, Nov. 29, 2006]

§ 63.7882 What site remediation sources at my facility does this subpart affect?

(a) This subpart applies to each new, reconstructed, or existing affected source for your site remediation as designated by paragraphs (a)(1) through (3) of this section.

(1) *Process vents.* The affected source is the entire group of process vents associated with the in-situ and ex-situ remediation processes used at your site to remove, destroy, degrade, transform, or immobilize hazardous substances in the remediation material subject to remediation. Examples of such in-situ remediation processes include, but are not limited to, soil vapor extraction and bioremediation processes. Examples of such ex-situ remediation processes include but are not limited to, thermal desorption, bioremediation, and air stripping processes.

(2) *Remediation material management units.* Remediation material management unit means a tank, surface impoundment, container, oil-water separator, organic-water separator, or transfer system, as defined in §63.7957, and is used at your site to manage remediation material. The affected source is the entire group of remediation material management units used for the site remediations at your site. For the purpose of this subpart, a tank or container that is also equipped with a vent that serves as a process vent, as defined in §63.7957, is not a remediation material management unit, but instead this unit is considered to be a process vent affected source under paragraph (a)(1) of this section.

(3) *Equipment leaks.* The affected source is the entire group of equipment components (pumps, valves, etc.) used to manage remediation materials and meeting both of the conditions specified in paragraphs (a)(3)(i) and (ii) of this section. If either of these conditions do not apply to an equipment component, then that component is not part of the affected source for equipment leaks.

(i) The equipment component contains or contacts remediation material having a concentration of total HAP listed in Table 1 of this subpart equal to or greater than 10 percent by weight.

(ii) The equipment component is intended to operate for 300 hours or more during a calendar year in remediation material service, as defined in §63.7957.

(b) Each affected source for your site is existing if you commenced construction or reconstruction of the affected source before July 30, 2002.

(c) Each affected source for your site is new if you commenced construction or reconstruction of the affected source on or after July 30, 2002. An affected source is reconstructed if it meets the definition of reconstruction in §63.2.

§ 63.7883 When do I have to comply with this subpart?

(a) If you have an existing affected source, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you no later than October 9, 2006.

(b) If you have a new affected source that manages remediation material other than a radioactive mixed waste as defined in §63.7957, then you must meet the compliance date specified in paragraph (b)(1) or (2) of this section, as applicable to your affected source.

(1) If the affected source's initial startup date is on or before October 8, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you by October 8, 2003.

(2) If the affected source's initial startup date is after October 8, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you upon initial startup.

(c) If you have a new affected source that manages remediation material that is a radioactive mixed waste as defined in §63.7957, then you must meet the compliance date specified in paragraph (c)(1) or (2) of this section, as applicable to your affected source.

(1) If the affected source's initial startup date is on or before October 8, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you no later than October 9, 2006.

(2) If the affected source's initial startup date is after October 8, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you upon initial startup.

(d) If your facility is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP as defined in §63.2, then you must meet the compliance dates specified in paragraphs (d)(1) and (2) of this section.

(1) For each source at your facility that is a new affected source subject to this subpart, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you upon initial startup.

(2) For all other affected sources subject to this subpart, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you no later than 3 years after your facility becomes a major source.

(e) You must meet the notification requirements, according to the schedule applicable to your facility, as specified in §63.7950 and in 40 CFR part 63, subpart A. Some of the notifications must be submitted before you are required to comply with the emissions limitations and work practice standards in this subpart.

General Standards

§ 63.7884 What are the general standards I must meet for each site remediation with affected sources?

(a) For each site remediation with an affected source designated under §63.7882, you must meet the standards specified in §§63.7885 through 63.7955, as applicable to your affected source, unless your site remediation meets the requirements for an exemption under paragraph (b) of this section.

(b) A site remediation that is completed within 30 consecutive calendar days according to the conditions in paragraphs (b)(1) through (3) of this section is not subject to the standards under paragraph (a) of this section. This exemption cannot be used for a site remediation involving the staged or intermittent cleanup of remediation material whereby the remediation activities at the site are started, stopped, and then re-started in a series of intervals, with durations less than 30-days per interval, when the time period from the beginning of the first interval to the end of the last interval exceeds 30 days.

(1) The 30 consecutive calendar day period for a site remediation that qualifies for this exemption is determined according to actions taken by you as defined in paragraphs (b)(1)(i) through (iii) of this section.

(i) The first day of the 30-day period is defined as the day on which you initiate any action that removes, destroys, degrades, transforms, immobilizes, or otherwise manages the remediation materials. The following activities, when completed before beginning this initial action, are not counted as part of the 30-day period: Activities to characterize the type and extent of the contamination by collecting and analyzing samples; activities to obtain permits from Federal, State, or local authorities to conduct the site remediation; activities to schedule workers and necessary equipment; and activities to arrange for contractor or third party assistance in performing the site remediation.

(ii) The last day of the 30-day period is defined as the day on which treatment or disposal of all of the remediation materials generated by the cleanup is completed such that the organic constituents in these materials no longer have a reasonable potential for volatilizing and being released to the atmosphere.

(iii) If treatment or disposal of the remediation materials is conducted at an off-site facility where the final treatment or disposal of the material cannot, or may not, be completed within the 30-day exemption period, then the shipment of all of the remediation material generated from your cleanup that is transferred to another party, or shipped to another facility, within the 30-day period, must be performed according to the applicable requirements specified in §63.7936.

(2) For the purpose of complying with paragraph (b)(1) of this section, if you ship or otherwise transfer the remediation material off-site you must include in the applicable shipping documentation, in addition to any notifications and certifications required under §63.7936, a statement that the shipped material was generated by a site remediation activity subject to the conditions of this exemption. The statement must include the date on which you initiated the site remediation activity generating the shipped remediation materials, as specified in paragraph (b)(1)(i) of this section, and the date 30 calendar days following your initiation date.

(3) You must prepare and maintain at your facility written documentation describing the exempted site remediation, and listing the initiation and completion dates for the site remediation.

[71 FR 69016, Nov. 29, 2006]

§ 63.7885 What are the general standards I must meet for my affected process vents?

(a) For the process vents that comprise the affected source designated under §63.7882, you must select and meet the requirements under one of the options specified in paragraph (b) of this section.

(b) For each affected process vent, except as exempted under paragraph (c) of this section, you must meet one of the options in paragraphs (b)(1) through (3) of this section.

(1) You control HAP emissions from the affected process vents according to the standards specified in §§63.7890 through 63.7893.

(2) You determine for the remediation material treated or managed by the process vented through the affected process vents that the average total volatile organic hazardous air pollutant (VOHAP) concentration, as defined in §63.7957, of this material is less than 10 parts per million by weight (ppmw). Determination of the VOHAP concentration is made using the procedures specified in §63.7943.

(3) If the process vent is also subject to another subpart under 40 CFR part 61 or 40 CFR part 63, you control emissions of the HAP listed in Table 1 of this subpart from the affected process vent in compliance with the standards specified in the applicable subpart. This means you are complying with all applicable emissions limitations and work practice standards under the other subpart (*e.g.,* you install and operate the required air pollution controls or have implemented the required work practice to reduce HAP emissions to levels specified by the applicable subpart). This provision does not apply to any exemption of the affected source from the emissions limitations and work practice standards allowed by the other applicable subpart.

(c) A process vent that meets the exemption requirements in paragraphs (c)(1) and (2) of this section is exempted from the requirements in paragraph (b) of this section.

(1) The process vent stream exiting the process vent meets the conditions in either paragraph (c)(1)(i) or (ii) of this section.

(i) The process vent stream flow rate is less than 0.005 cubic meters per minute (m^3 /min) at standard conditions (as defined in 40 CFR 63.2); or

(ii) The process vent stream flow rate is less than 6.0 m^3 /min at standard conditions (as defined in 40 CFR 63.2) and the total concentration of HAP listed in Table 1 of this subpart is less than 20 parts per million by volume (ppmv).

(2) You must demonstrate that the process vent stream meets the applicable exemption conditions in paragraph (c)(1) of this section using the procedures specified in §63.694(m). You must prepare and maintain documentation at your facility to support your determination of the process vent stream flow rate. This documentation must include identification of each process vent exempted under this paragraph and the test results used to determine the process vent stream flow rate and total HAP concentration, as applicable to the exemption conditions for your process vent. You must perform a new determination of the process vent stream flow rate and total HAP concentration, as applicable to the exemption conditions for your process vent, whenever changes to operation of the unit on which the process vent is used could cause the process vent stream conditions to exceed the maximum limits of the exemption.

§ 63.7886 What are the general standards I must meet for my affected remediation material management units?

(a) For each remediation material management unit that is part of an affected source designated by §63.7882, you must select and meet the requirements under one of the options specified in paragraph (b) of this section except for those remediation material management units exempted under paragraph (c) or (d) of this section.

(b) For each affected remediation material management unit, you must meet one of the options in paragraphs (b)(1) through (4) of this section.

(1) You control HAP emissions from the affected remediation material management unit according to the standards specified in paragraphs (b)(1)(i) through (v) of this section, as applicable to the unit.

(i) If the remediation material management unit is a tank, then you control HAP emissions according to the standards specified in §§63.7895 through 63.7898.

(ii) If the remediation material management unit is a container, then you control HAP emissions according to the standards specified in §§63.7900 through 63.7903.

(iii) If the remediation material management unit is a surface impoundment, then you control HAP emissions according to the standards specified in §§63.7905 through 63.7908.

(iv) If the remediation material management unit is an oil-water or organic-water separator, then you control HAP emissions according to the standards specified in §§63.7910 through 63.7913.

(v) If the remediation material management unit is a transfer system, then you control HAP emissions according to the standards specified in §§63.7915 through 63.7918.

(2) You determine that the average total VOHAP concentration, as defined in §63.7957, of the remediation material managed in the remediation material management unit material is less than 500 ppmw. You must follow the requirements in §63.7943 to demonstrate that the VOHAP concentration of the remediation material is less than 500 ppmw. Once the VOHAP concentration for a remediation material has been determined to be less than 500 ppmw, all remediation material management units downstream from the point of determination managing this material meet the requirements of this paragraph unless a remediation process is used that concentrates all, or part of, the remediation material being managed in the unit such that the VOHAP concentration of the material could increase. Any free product returned to the manufacturing process (*e.g.* , recovered oil returned to a storage tank at a refinery) is no longer subject to this subpart.

(3) If the remediation material management unit is also subject to another subpart under 40 CFR part 61 or 40 CFR part 63, you control emissions of the HAP listed in Table 1 of this subpart from the affected remediation material management unit in compliance with the standards specified in the applicable subpart. This means you are complying with all applicable emissions limitations and work practice standards under the other subpart (*e.g.,* you install and operate the required air pollution controls or have implemented the required work practice to reduce HAP emissions to levels specified by the applicable subpart). This provision does not apply to any exemption of the affected source from the emissions limitations and work practice standards allowed by the other applicable subpart.

(4) If the remediation material management unit is an open tank or surface impoundment used for a biological treatment process, you meet the requirements as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) You demonstrate that the biological treatment process conducted in the open tank or surface impoundment meets the performance levels specified in either §63.684(b)(4)(i) or (ii).

(ii) You monitor the biological treatment process conducted in the open tank or surface impoundment according to the requirements in §63.684(e)(4).

(c) A remediation material management unit is exempted from the requirements in paragraph (b) of this section if this unit is used for cleanup of radioactive mixed waste, as defined in §63.7957, that is subject to applicable regulations, directives, and other requirements under the Atomic Energy Act, the Nuclear Waste Policy Act, or the Waste Isolation Pilot Plant Land Withdrawal Act.

(d) One or a combination of remediation material management units may be exempted at your discretion from the requirements in paragraph (b) of this section provided that the total annual quantity of HAP listed in Table 1 of this subpart contained in the remediation material placed in all of the remediation material management units exempted under this paragraph is less than 1 Mg/yr. For each remediation material management unit you select to be exempted under this provision, you must meet the requirements in paragraphs (d)(1) and (2) of this section.

(1) You must designate each of the remediation material management units you are selecting to be exempted under this paragraph by either submitting to the Administrator a written notification identifying the exempt units or permanently marking the exempt units at the faculty site. If you choose to prepare and submit a written notification, this notification must include a site plan, process diagram, or other appropriate documentation identifying each of the exempt units. If you choose to permanently mark the exempt units, each exempt unit must be marked in such a manner that it can be readily identified as an exempt unit from the other remediation material management units located at the site.

(2) You must prepare an initial determination of the total annual HAP quantity in the remediation material placed in the units exempted under this paragraph. This determination is based on the total quantity of the HAP listed in Table 1 of this subpart as determined at the point where the remediation material is placed in each exempted unit. You must perform a new determination whenever the extent of changes to the quantity or composition of the remediation material placed in the exempted units could cause the total annual HAP content in the remediation material to exceed 1 Mg/yr. You must maintain documentation to support the most recent determination of the total annual HAP quantity. This documentation must include the basis and data used for determining the organic HAP content of the remediation material.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69017, Nov. 29, 2006]

§ 63.7887 What are the general standards I must meet for my affected equipment leak sources?

(a) You must control HAP emissions from equipment leaks from each equipment component that is part of the affected source by implementing leak detection and control measures according to the standards specified in §§63.7920 through 63.7922 unless you elect to meet the requirements in paragraph (b) of this section.

(b) If the affected equipment leak source is also subject to another subpart in 40 CFR part 61 or 40 CFR part 63, you may control emissions of the HAP listed in Table 1 to this subpart from the affected equipment leak source in compliance with the standards specified in the other applicable subpart. This means you are complying with all applicable emissions limitations and work practice standards under the other subpart (*e.g.* , you implement leak detection and control measures to reduce HAP emissions as specified by the applicable subpart). This provision does not apply to any exemption of the affected source from the emissions limitations and work practice standards allowed by the other applicable subpart.

[71 FR 69017, Nov. 29, 2006]

§ 63.7888 How do I implement this rule at my facility using the cross-referenced requirements in other subparts?

(a) For the purposes of this subpart, when you read the term "HAP listed in Table 1 of this subpart" in a cross-referenced section under 40 CFR part 63, subpart DD—National Emission Standards for Hazardous Air Pollutants from Off-Site Waste and Recovery Operations, you should refer to Table 1 of this subpart.

(b) For the purposes of this subpart, when you read the term off-site material in a cross-referenced section under 40 CFR part 63, subpart DD—National Emission Standards for Hazardous Air Pollutants from Off-Site Waste and Recovery Operations you should substitute the term remediation material, as defined in §63.7957.

(c) For the purposes of this subpart, when you read the term regulated material in a cross-referenced section under 40 CFR part 63, subparts OO, PP, QQ, RR, TT, UU, WW, and VV you should substitute the term remediation material, as defined in §63.7957.

Process Vents

§ 63.7890 What emissions limitations and work practice standards must I meet for process vents?

(a) You must control HAP emissions from each new and existing process vent subject to §63.7885(b)(1) according to emissions limitations and work practice standards in this section that apply to your affected process vents.

(b) For your affected process vents, you must meet one of the facility-wide emission limit options specified in paragraphs (b)(1) through (4) of this section. If you have multiple affected process vent streams, you may comply with this paragraph using a combination of controlled and uncontrolled process vent streams that achieve the facility-wide emission limit that applies to you.

(1) Reduce from all affected process vents the total emissions of the HAP listed in Table 1 of this subpart to a level less than 1.4 kilograms per hour (kg/hr) and 2.8 Mg/yr (3.0 pounds per hour (lb/hr) and 3.1 tpy); or

(2) Reduce from all affected process vents the emissions of total organic compounds (TOC) (minus methane and ethane) to a level below 1.4 kg/hr and 2.8 Mg/yr (3.0 lb/hr and 3.1 tpy); or

(3) Reduce from all affected process vents the total emissions of the HAP listed in Table 1 of this subpart by 95 percent by weight or more; or

(4) Reduce from all affected process vents the emissions of TOC (minus methane and ethane) by 95 percent by weight or more.

(c) For each closed vent system and control device you use to comply with paragraph (b) of this section, you must meet the operating limit requirements and work practice standards in §63.7925(c) through (j) that apply to your closed vent system and control device.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69017, Nov. 29, 2006]

§ 63.7891 How do I demonstrate initial compliance with the emissions limitations and work practice standards for process vents?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7890(b) applicable to your affected process vents by meeting the requirements in paragraphs (b) through (d) of this section.

(b) You have measured or determined using the procedures for performance tests and design evaluations in §63.7941 that emission levels from all of your affected process vents meet the facility-wide emission limits in §63.7890(b) that apply to you, as follows in paragraphs (b)(1) through (4) of this section.

(1) If you elect to meet §63.7890(b)(1), you demonstrate that the total emissions of the HAP listed in Table 1 of this subpart from all affected process vents at your facility are less than 1.4 kg/hr and 2.8 Mg/yr (3.0 lb/hr and 3.1 tpy).

(2) If you elect to meet §63.7890(b)(2), you demonstrate that emissions of TOC (minus methane and ethane) from all affected process vents at your facility are less than 1.4 kg/hr and 2.8 Mg/yr (3.0 lb/hr and 3.1 tpy).

(3) If you elect to meet §63.7890(b)(3), you demonstrate that the total emissions of the HAP listed in Table 1 of this subpart from all affected process vents are reduced by 95 percent by weight or more.

(4) If you elect to meet §63.7890(b)(4), you demonstrate that the emissions of TOC (minus methane and ethane) from all affected process vents are reduced by 95 percent by weight or more.

(c) For each closed vent system and control device you use to comply with §63.7890(b), you have met each requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

(d) You have submitted a notification of compliance status according to the requirements in §63.7950.

§ 63.7892 What are my inspection and monitoring requirements for process vents?

For each closed vent system and control device you use to comply with §63.7890(b), you must monitor and inspect the closed vent system and control device according to the requirements in §63.7927 that apply to you.

§ 63.7893 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for process vents?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7890 applicable to your affected process vents by meeting the requirements in paragraphs (b) through (d) of this section.

(b) You must maintain emission levels from all of your affected process vents to meet the facilitywide emission limits in §63.7890(b) that apply to you, as specified in paragraphs (b)(1) through (4) of this section.

(1) If you elect to meet §63.7890(b)(1), you maintain the total emissions of the HAP listed in Table 1 of this subpart from all affected process vents at your facility are less than 1.4 kg/hr and 2.8 Mg/yr (3.0 lb/hr and 3.1 tpy).

(2) If you elect to meet §63.7890(b)(2), you maintain emissions of TOC (minus methane and ethane) from all affected process vents at your facility are less than 1.4 kg/hr and 2.8 Mg/yr (3.0 lb/hr and 3.1 tpy).

(3) If you elect to meet §63.7890(b)(3), you maintain the total emissions of the HAP listed in Table 1 of this subpart from all affected process vents are reduced by 95 percent by weight or more.

(4) If you elect to meet §63.7890(b)(4), you maintain that the emissions of TOC (minus methane and ethane) from all affected process vents are reduced by 95 percent by weight or more.

(c) For each closed vent system and control device you use to comply with §63.7890(b), you have met each requirement for demonstrating continuous compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7928.

(d) Keeping records to document continuous compliance with the requirements of this subpart according to the requirements in §63.7952.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69017, Nov. 29, 2006]

Tanks

§ 63.7895 What emissions limitations and work practice standards must I meet for tanks?

(a) You must control HAP emissions from each new and existing tank subject to §63.7886(b)(1)(i) according to emissions limitations and work practice standards in this section that apply to your affected tanks.

(b) For each affected tank, you must install and operate air pollution controls that meet the requirements in paragraphs (b)(1) through (4) of this section that apply to your tank.

(1) Unless your tank is used for a waste stabilization process, as defined in §63.7957, you must determine the maximum HAP vapor pressure (expressed in kilopascals (kPa)) of the remediation material placed in your tank using the procedures specified in §63.7944.

(2) If the maximum HAP vapor pressure of the remediation material you place in your tank is less than 76.6 kPa, then you must determine which tank level controls (*i.e.,* Tank Level 1 or Tank Level 2) apply to your tank as shown in Table 2 of this subpart, and based on your tank's design capacity (expressed in cubic meters (m^3)) and the maximum HAP vapor pressure of the remediation material you place in this tank. If your tank is required by Table 2 of this subpart to use Tank Level 1 controls, then you must meet the requirements in paragraph (c) of this section. If your tank is required by Table 2 of this subpart to use Tank Level 2 controls, then you must meet the requirements in paragraph (d) of this section

(3) If maximum HAP vapor pressure of the remediation material you place in your tank is 76.6 kPa or greater, then the tank must use one of the Tank Level 2 controls specified in paragraphs (d)(3) through (5) of this section. Use of floating roofs under paragraph (d)(1) or (2) of this section is not allowed for tanks managing these remediation materials.

(4) A tank used for a waste stabilization process, as defined in §63.7957, must use one of Tank Level 2 controls, as specified in paragraph (d) of this section, that is appropriate for your waste stabilization process.

(c) If you use Tank Level 1 controls, you must install and operate a fixed roof according to the requirements in §63.902. As an alternative to using this fixed roof, you may choose to use one of Tank Level 2 controls in paragraph (d) of this section.

(d) If you use Tank Level 2 controls, you must meet the requirements of one of the options in paragraphs (d)(1) through (5) of this section.

(1) Install and operate a fixed roof with an internal floating roof according to the requirements in §63.1063(a)(1)(i), (a)(2), and (b); or

(2) Install and operate an external floating roof according to the requirements in §63.1063(a)(1)(ii), (a)(2), and (b); or

(3) Install and operate a fixed roof vented through a closed vent system to a control device according to the requirements in §63.685(g). You must meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device; or

(4) Install and operate a pressure tank according to the requirements in §63.685(h); or

(5) Locate the tank inside a permanent total enclosure and vent emissions from the enclosure through a closed vent system to a control device that is an enclosed combustion device according to the requirements in §63.685(i). You must meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device.

(e) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your tanks. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

§ 63.7896 How do I demonstrate initial compliance with the emissions limitations and work practice standards for tanks?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7895 that apply to your affected tanks by meeting the requirements in paragraphs (b) through (h) of this section, as applicable to your containers.

(b) You have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(1) and (2) of this section.

(1) You have determined the applicable tank control levels specified in §63.7895(b) for the tanks to be used for your site remediation.

(2) You have determined, according to the procedures in §63.7944, and recorded the maximum HAP vapor pressure of the remediation material placed in each affected tank subject to §63.7886(b)(1)(i) that does not use Tank Level 2 controls.

(c) You must demonstrate initial compliance of each tank determined under paragraph (b) of this section to require Tank Level 1 controls if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(1) through (3) of this section.

(1) Each tank using Tank Level 1 controls is equipped with a fixed roof and closure devices according to the requirements in §63.902(b) and (c) and you have records documenting the design.

(2) You have performed an initial visual inspection of the fixed roof and closure devices for defects according to the requirements in §63.906(a) and you have records documenting the inspection results.

(3) You will operate the fixed roof and closure devices according to the requirements in §63.902.

(d) You must demonstrate initial compliance of each tank determined under paragraph (b) of this section to require Tank Level 2 controls and using a fixed roof with an internal floating roof according to §63.7895(d)(1) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (d)(1) through (3) of this section.

(1) Each tank is equipped with an internal floating roof that meets the requirements in §63.1063(a) and you have records documenting the design.

(2) You will operate the internal floating roof according to the requirements in §63.1063(b).

(3) You have performed an initial visual inspection according to the requirements in §63.1063(d)(1) and you have a record of the inspection results.

(e) You must demonstrate initial compliance of each tank determined under paragraph (b) of this section to require Tank Level 2 controls and using an external floating roof according to §63.7895(d)(2) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (e)(1) through (3) of this section.

(1) Each tank is equipped with an external floating roof that meets the requirements in §63.1063(a) and you have records documenting the design.

(2) You will operate the external floating roof according to the requirements in §63.1063(b).

(3) You have performed an initial seal gap measurement inspection according to the requirements in §63.1063(d)(3) and you have records of the measurement results.

(f) You must demonstrate initial compliance of each tank determined under paragraph (b) of this section to require Tank Level 2 controls and using a fixed roof vented to a control device according to §63.7895(d)(3) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (f)(1) through (4) of this section.

(1) Each tank is equipped with a fixed roof and closure devices according to the requirements in §63.902(b) and (c) and you have records documenting the design.

(2) You have performed an initial visual inspection of fixed roof and closure devices for defects according to the requirements in §63.695(b)(3) and you have records documenting the inspection results.

(3) You will operate the fixed roof and closure devices according to the requirements in §63.685(g).

(4) You have met each applicable requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

(g) You must demonstrate initial compliance of each tank determined under paragraph (b) of this section to require Tank Level 2 controls and operates as a pressure tank according to §63.7895(d)(4) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (g)(1) and (2) of this section.

(1) Each tank is designed to operate as a pressure tank according to the requirements in §63.685(h), and you have records documenting the design.

(2) You will operate the pressure tank and according to the requirements in §63.685(h).

(h) You must demonstrate initial compliance of each tank determined under paragraph (b) of this section to require Tank Level 2 controls and using a permanent total enclosure vented to an enclosed combustion device according to §63.7895(d)(5) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (h)(1) and (2) of this section.

(1) You have submitted as part of your notification of compliance status a signed statement that you have performed the verification procedure according to the requirements in §63.685(i), and you have records of the supporting calculations and measurements.

(2) You have met each applicable requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69016, Nov. 29, 2006]

§ 63.7897 What are my inspection and monitoring requirements for tanks?

(a) You must visually inspect each of your tanks using Tank Level 1 controls for defects at least annually according to the requirements in §63.906(a).

(b) You must inspect and monitor each of your tanks using Tank Level 2 controls according to the requirements in paragraphs (b)(1) through (5), as applicable to your tanks.

(1) If you use a fixed roof with an internal floating roof according to §63.7895(d)(1), you must visually inspect the fixed roof and internal floating roof according to the requirements in §63.1063(d)(1) and (2).

(2) If you use an external floating roof according to §63.7895(d)(2), you must visually inspect the external floating roof according to the requirements in §63.1063(d)(1) and inspect the seals according to the requirements in §63.1063(d)(2) and (3).

(3) If you use a fixed roof vented to a control device according to §63.7895(d)(3), you must meet requirements in paragraphs (b)(3)(i) and (ii) of this section.

(i) You must visually inspect the fixed roof and closure devices for defects according to the requirements in §63.695(b)(3).

(ii) You must monitor and inspect the closed vent system and control device according to the requirements in §63.7927 that apply to you.

(4) If you use a pressure tank according to §63.7895(d)(4), you must visually inspect the tank and its closure devices for defects at least annually to ensure they are operating according to the design requirements in §63.685(h).

(5) If you use a permanent total enclosure vented to an enclosed combustion device according to §63.7895(d)(5), you must meet requirements in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must perform the verification procedure for the permanent total enclosure at least annually according to the requirements in §63.685(i).

(ii) You must monitor and inspect the closed vent system and control device according to the requirements in §63.7927 that apply to you.

§ 63.7898 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for tanks?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7895 applicable to your affected tanks by meeting the requirements in paragraphs (b) through (d) of this section.

(b) You must demonstrate continuous compliance with the requirement to determine the applicable tank control level specified in §63.7895(b) for each affected tank by meeting the requirements in paragraphs (b)(1) through (3) of this section.

(1) Keeping records of the tank design capacity according to the requirements in §63.1065(a).

(2) For tanks subject to §63.7886(b)(1)(ii) and not using Tank Level 2 controls, meeting the requirements in paragraphs (b)(2)(i) and (ii) of this section.

(i) Keeping records of the maximum HAP vapor pressure determined according to the procedures in §63.7944 for the remediation material placed in each affected tank.

(ii) Performing a new determination of the maximum HAP vapor pressure whenever changes to the remediation material managed in the tank could potentially cause the maximum HAP vapor pressure to increase to a level that is equal to or greater than the maximum HAP vapor pressure for the tank design capacity specified in Table 2. You must keep records of each determination.

(3) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(c) You must demonstrate continuous compliance for each tank determined to require Tank Level 1 controls by meeting the requirements in paragraphs (c)(1) through (5) of this section.

(1) Operating and maintaining the fixed roof and closure devices according to the requirements in §63.902(c).

(2) Visually inspecting the fixed roof and closure devices for defects at least annually according to the requirements in §63.906(a).

(3) Repairing defects according to the requirements in §63.63.906(b).

(4) Recording the information specified in §63.907(a)(3) and (b).

(5) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(d) You must demonstrate continuous compliance for each tank determined to require Tank Level 2 controls and using a fixed roof with an internal floating roof according to §63.7895(d)(1) by meeting the requirements in paragraphs (d)(1) through (5) of this section.

(1) Operating and maintaining the internal floating roof according to the requirements in §63.1063(b).

(2) Visually inspecting the internal floating roof according to the requirements in §63.1063(d)(1) and (2).

(3) Repairing defects according to the requirements in §63.1063(e).

(4) Recording the information specified in §63.1065(b) through (d).

(5) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(e) You must demonstrate continuous compliance for each tank determined to require Tank Level 2 controls and using an external floating roof according to §63.7895(d)(2) by meeting the requirements in paragraphs (e)(1) through (5) of this section.

(1) Operating and maintaining the external floating roof according to the requirements in §63.1063(b).

(2) Visually inspecting the external floating roof according to the requirements in §63.1063(d)(1) and inspecting the seals according to the requirements in §63.1063(d)(2) and (3).

(3) Repairing defects according to the requirements in §63.1063(e).

(4) Recording the information specified in §63.1065(b) through (d).

(5) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(f) You must demonstrate continuous compliance for each tank determined to require Tank Level 2 controls and using a fixed roof vented to a control device according to §63.7895(d)(3) by meeting the requirements in paragraphs (f)(1) through (6) of this section.

(1) Operating and maintaining the fixed roof and closure devices according to the requirements in §63.685(g).

(2) Visually inspecting the fixed roof and closure devices for defects at least annually according to the requirements in §63.695(b)(3)(i).

(3) Repairing defects according to the requirements in §63.695(b)(4).

(4) Recording the information specified in §63.696(e).

(5) Meeting each applicable requirement for demonstrating continuous compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7928.

(6) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(g) You must demonstrate continuous compliance for each tank determined to require Tank Level 2 controls and operated as a pressure tank according to §63.7895(d)(4) by meeting the requirements in paragraphs (g)(1) through (3) of this section.

(1) Operating and maintaining the pressure tank and closure devices according to the requirements in §63.685(h).

(2) Visually inspecting each pressurized tank and closure devices for defects at least annually to ensure they are operating according to the design requirements in §63.685(h), and recording the results of each inspection.

(3) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(h) You must demonstrate continuous compliance for each tank determined to require Tank Level 2 controls and using a permanent total enclosure vented to an enclosed combustion device according to §63.7895(d)(5) by meeting the requirements in paragraphs (h)(1) through (4) of this section.

(1) Performing the verification procedure for the enclosure annually according to the requirements in §63.685(i).

(2) Recording the information specified in §63.696(f).

(3) Meeting each applicable requirement for demonstrating continuous compliance with the emissions limitations and work practice standards for a closed vent system and control device in §63.7928.

(4) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69017, Nov. 29, 2006]

Containers

§ 63.7900 What emissions limitations and work practice standards must I meet for containers?

(a) You must control HAP emissions from each new and existing container subject to §63.7886(b)(1)(ii) according to emissions limitations and work practice standards in this section that apply to your affected containers.

(b) For each container having a design capacity greater than 0.1 m^3 you must meet the requirements in paragraph (b)(1) or (2) of this section that apply to your container except at the times the container is used for treatment of remediation material by a waste stabilization process, as defined in §63.7957. As an alternative for any container subject to this paragraph, you may choose to meet the requirements in paragraph (d) of this section.

(1) If the design capacity of your container is less than or equal to 0.46 m^3 , then you must use controls according to the standards for Container Level 1 controls as specified in §63.922. As an alternative, you may choose to use controls according to either of the standards for Container Level 2 controls as specified in §63.923.

(2) If the design capacity of your container is greater than 0.46 m^3 , then you must use controls according to the standards for Container Level 2 controls as specified in §63.923 except as provided for in paragraph (b)(3) of this section.

(3) As an alternative to meeting the standards in paragraph (b)(2) of this section for containers with a capacity greater than 0.46 m^3 , if you determine that either of the conditions in paragraphs (b)(3)(i) or (ii) apply to the remediation material placed in your container, then you may use controls according to the standards for Container Level 1 controls as specified in §63.922.

(i) Vapor pressure of every organic constituent in the remediation material placed in your container is less than 0.3 kPa at 20 °C; or

(ii) Total concentration of the pure organic constituents having a vapor pressure greater than 0.3 kPa at 20 °C in the remediation material placed in your container is less than 20 percent by weight.

(c) At times when a container having a design capacity greater than 0.1 m^3 is used for treatment of a remediation material by a waste stabilization process as defined in §63.7957, you must control air emissions from the container during the process whenever the remediation material in the container is exposed to the atmosphere according to the standards for Container Level 3 controls as specified in §63.924. You must meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device.

(d) As an alternative to meeting the requirements in paragraph (b) of this section, you may choose to use controls on your container according to the standards for Container Level 3 controls as specified in §63.924. You must meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device.

(e) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your containers. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

§ 63.7901 How do I demonstrate initial compliance with the emissions limitations and work practice standards for containers?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7990 that apply to your affected containers by meeting the requirements in paragraphs (b) through (e) of this section, as applicable to your containers.

(b) You have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(1) and (2) of this section.

(1) You have determined the applicable container control levels specified in §63.7990 for the containers to be used for your site remediation.

(2) You have determined and recorded the maximum vapor pressure or total organic concentration for the remediation material placed in containers with a design capacity greater than 0.46 m^3 , and do not use Container Level 2 or Level 3 controls.

(c) You must demonstrate initial compliance of each container determined under paragraph (b) of this section to require Container Level 1 controls if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(1) and (2) of this section.

(1) Each container using Container Level 1 controls will be one of the containers specified in §63.922(b).

(2) You will operate each container cover and closure device according to the requirements in §63.922(d).

(d) You must demonstrate initial compliance of each container determined under paragraph (b) of this section to require Container Level 2 controls if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (d)(1) through (4) of this section.

(1) Each container using Container Level 2 controls will be one of the containers specified in §63.923(b).

(2) You will transfer remediation materials into and out of each container according to the procedures in §63.923(d).

(3) You will operate and maintain the container covers and closure devices according to the requirements in §63.923(d).

(4) You have records that the container meets the applicable U.S. Department of Transportation regulations, or you have conducted an initial test of each container for no detectable organic emissions using the procedures in §63.925(a), and have records documenting the test results, or you have demonstrated within the last 12 months that each container is vapor-tight according to the procedures in §63.925(a) and have records documenting the test results.

(e) You must demonstrate initial compliance of each container determined under paragraph (b) of this section to require Container Level 3 controls if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (e)(1) and (2) of this section.

(1) For each permanent total enclosure you use to comply with §63.7900, you have performed the verification procedure according to the requirements in §63.924(c)(1), and prepare records of the supporting calculations and measurements.

(2) You have met each applicable requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

§ 63.7902 What are my inspection and monitoring requirements for containers?

(a) You must inspect each container using Container Level 1 or Container Level 2 controls according to the requirements in §63.926(a).

(b) If you use Container Level 3 controls, you must meet requirements in paragraphs (b)(1) and (2) of this section, as applicable to your site remediation.

(1) You must perform the verification procedure for each permanent total enclosure annually according to the requirements in §63.924(c)(1).

(2) You must monitor and inspect each closed vent system and control device according to the requirements in §63.7927 that apply to you.

§ 63.7903 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for containers?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7990 applicable to your affected containers by meeting the requirements in paragraphs (b) through (e) of this section.

(b) You must demonstrate continuous compliance with the requirement to determine the applicable container control level specified in §63.7990(b) for each affected tank by meeting the requirements in paragraphs (b)(1) through (3) of this section.

(1) Keeping records of the quantity and design capacity for each type of container used for your site remediation and subject to §63.7886(b)(1)(ii).

(2) For containers subject to §63.7886(b)(1)(ii) with a design capacity greater than 0.46 m^3 and not using Container Level 2 or Container Level 3 controls, meeting the requirements in paragraphs (b)(2)(i) and (ii) of this section.

(i) Keeping records of the maximum vapor pressure or total organic concentration for the remediation material placed in the containers, as applicable to the conditions in §63.7900(b)(3)(i) or (ii) for which your containers qualify to use Container Level 1 controls.

(ii) Performing a new determination whenever changes to the remediation material placed in the containers could potentially cause the maximum vapor pressure or total organic concentration to increase to a level that is equal to or greater than the conditions specified in §63.7900(b)(3)(i) or (ii), as applicable to your containers. You must keep records of each determination.

(3) Keeping records to document compliance with the requirements according to the requirements in §63.7952.

(c) You must demonstrate continuous compliance for each container determined to require Container Level 1 controls by meeting the requirements in paragraphs (c)(1) through (5) of this section.

(1) Operating and maintaining covers for each container according to the requirements in §63.922(d) .

(2) Inspecting each container annually according to the requirements in §63.926(a)(2).

(3) Emptying or repairing each container according to the requirements in §63.926(a)(3).

(4) Keeping records of an inspection that includes the information in paragraphs (a)(4)(i) and (ii) of this section.

(i) Date of each inspection; and

(ii) If a defect is detected during an inspection, the location of the defect, a description of the defect, the date of detection, the corrective action taken to repair the defect, and if repair is delayed, the reason for any delay and the date completion of the repair is expected.

(5) Keeping records to document compliance with the requirements according to the requirements in §63.7952.

(d) You must demonstrate continuous compliance for each container determined to require Container Level 2 controls by meeting the requirements in paragraphs (d)(1) through (6) of this section.

(1) Transferring remediation material in and out of the container according to the requirements in §63.923(c).

(2) Operating and maintaining container covers according to the requirements in §63.923(d).

(3) Inspecting each container annually according to the requirements in §63.926(a)(2).

(4) Emptying or repairing containers according to the requirements in §63.926(a)(3).

(5) Keeping records of each inspection that include the information in paragraphs (d)(5)(i) and (ii) of this section.

(i) Date of each inspection; and

(ii) If a defect is detected during an inspection, the location of the defect, a description of the defect, the date of detection, the corrective action taken to repair the defect, and if repair is delayed, the reason for any delay and the date completion of the repair is expected.

(6) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(e) You must demonstrate continuous compliance for each container determined to require Container Level 3 controls by meeting the requirements in paragraphs (e)(1) through (4) of this section.

(1) Performing the verification procedure for the enclosure annually according to the requirements in §63.685(i).

(2) Recording the information specified in §63.696(f).

(3) Meeting each applicable requirement for demonstrating continuous compliance with the emissions limitations and work practice standards for a closed vent system and control device in §63.7928.

(4) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

Surface Impoundments

§ 63.7905 What emissions limitations or work practice standards must I meet for surface impoundments?

(a) You must control HAP emissions from each new and existing surface impoundment subject to §63.7886(b)(1)(iii) according to emissions limitations and work practice standards in this section that apply to your affected surface impoundments.

(b) For each affected surface impoundment, you must install and operate air pollution controls that meet either of the options in paragraphs (b)(1) or (2) of this section.

(1) Install and operate a floating membrane cover according to the requirements in §63.942; or

(2) Install and operate a cover vented through a closed vent system to a control device according to the requirements in §63.943. You must meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device.

(c) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your surface impoundments. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

§ 63.7906 How do I demonstrate initial compliance with the emissions limitations or work practice standards for surface impoundments?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7905 that apply to your affected surface impoundments by meeting the requirements in paragraphs (b) and (c) of this section, as applicable to your surface impoundments.

(b) You must demonstrate initial compliance of each surface impoundment using a floating membrane cover according to §63.7905(b)(1) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(1) through (3) of this section.

(1) You have installed a floating membrane cover and closure devices that meet the requirements in §63.942(b), and you have records documenting the design and installation.

(2) You will operate the cover and closure devices according to the requirements in §63.942(c).

(3) You have performed an initial visual inspection of each surface impoundment and closure devices according to the requirements in §63.946(a), and you have records documenting the inspection results.

(c) You must demonstrate initial compliance of each surface impoundment using a cover vented to a control device according to §63.7905(b)(2) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(1) through (4) of this section.

(1) You have installed a cover and closure devices that meet the requirements in §63.943(b), and have records documenting the design and installation.

(2) You will operate the cover and closure devices according to the requirements in §63.943(c).

(3) You have performed an initial visual inspection of each cover and closure devices according to the requirements in §63.946(b), and have records documenting the inspection results.

(4) You have met each applicable requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

§ 63.7907 What are my inspection and monitoring requirements for surface impoundments?

(a) If you use a floating membrane cover according to §63.7905(b)(1), you must visually inspect the floating membrane cover and its closure devices at least annually according to the requirements in §63.946(a).

(b) If you use a cover vented to a control device according to §63.7905(b)(2), you must meet requirements in paragraphs (b)(1) and (2) of this section.

(1) You must visually inspect the cover and its closure devices for defects according to the requirements in §63.946(b).

(2) You must monitor and inspect the closed vent system and control device according to the requirements in §63.7927 that apply to you.

§ 63.7908 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for surface impoundments?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7905 applicable to your affected surface impoundments by meeting the requirements in paragraphs (b) and (c) of this section as applicable to your surface impoundments.

(b) You must demonstrate continuous compliance for each surface impoundment using a floating membrane cover according to §63.7905(b)(1) by meeting the requirements in paragraphs (b)(1) through (5) of this section.

(1) Operating and maintaining the floating membrane cover and closure devices according to the requirements in §63.942(c).

(2) Visually inspecting the floating membrane cover and closure devices for defects at least annually according to the requirements in §63.946(a).

(3) Repairing defects according to the requirements in §63.946(c).

(4) Recording the information specified in §63.947(a)(2) and (a)(3).

(5) Keeping records to document compliance with the requirements according to the requirements in §63.7952.

(c) You must demonstrate continuous compliance for each surface impoundment using a cover vented to a control device according to §63.7905(b)(2) by meeting the requirements in paragraphs (c)(1) through (6) of this section.

(1) Operating and maintaining the cover and its closure devices according to the requirements in §63.943(c).

(2) Visually inspecting the cover and its closure devices for defects at least annually according to the requirements in §63.946(b).

(3) Repairing defects according to the requirements in §63.946(c).

(4) Recording the information specified in §63.947(a)(2) and (a)(3).

(5) Meeting each applicable requirement for demonstrating continuous compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7928.

(6) Keeping records to document compliance with the requirements according to the requirements in §63.7952.

Separators

§ 63.7910 What emissions limitations and work practice standards must I meet for separators?

(a) You must control HAP emissions from each new and existing oil-water separator and organic-water separator subject to §63.7886(b)(1)(iv) according to emissions limitations and work practice standards in this section that apply to your affected separators.

(b) For each affected separator, you must install and operate air pollution controls that meet one of the options in paragraphs (b)(1) through (3) of this section.

(1) Install and operate a floating roof according to the requirements in §63.1043. For portions of the separator where it is infeasible to install and operate a floating roof, such as over a weir mechanism, you must comply with the requirements specified in paragraph (b)(2) of this section.

(2) Install and operate a fixed roof vented through a closed vent system to a control device according to the requirements in §63.1044. You must meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device.

(3) Install and operate a pressurized separator according to the requirements in §63.1045.

(c) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your separators. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

§ 63.7911 How do I demonstrate initial compliance with the emissions limitations and work practice standards for separators?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7910 that apply to your affected separators by meeting the requirements in paragraphs (b) through (d) of this section, as applicable to your separators.

(b) You must demonstrate initial compliance of each separator using a floating roof according to §63.7910(b)(1) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(1) through (4) of this section.

(1) You have installed a floating roof and closure devices that meet the requirements in §63.1043(b), and you have records documenting the design and installation.

(2) You will operate the floating roof and closure devices according to the requirements in §63.1043(c).

(3) You have performed an initial seal gap measurement inspection using the procedures in §63.1046(b), and you have records documenting the measurement results.

(4) You have performed an initial visual inspection of the floating roof and closure devices for defects according to the requirements in §63.1047(b)(2), and you have records documenting the inspection results.

(5) For any portions of the separator using a fixed roof vented to a control device according to §63.7910(b)(1), you have met the requirements in paragraphs (c)(1) through (4) of this section.

(c) You must demonstrate initial compliance of each separator using a fixed roof vented to a control device according to §63.7910(b)(2) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(1) through (4) of this section.

(1) You have installed a fixed roof and closure devices that meet the requirements in §63.1042(b), and you have records documenting the design and installation.

(2) You will operate the fixed roof and its closure devices according to the requirements in §63.1042(c).

(3) You have performed an initial visual inspection of the fixed roof and closure devices for defects according to the requirements in §63.1047(a).

(4) You have met each applicable requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

(d) You must demonstrate initial compliance of each pressurized separator that operates as a closed system according to §63.7910(b)(3) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (d)(1) and (2) of this section.

(1) You have installed a pressurized separator that operates as a closed system according to the requirements in §63.1045(b)(1) and (b)(2), and you have records of the design and installation.

(2) You will operate the pressurized separator as a closed system according to the requirements in §63.1045(b)(3).

§ 63.7912 What are my inspection and monitoring requirements for separators?

(a) If you use a floating roof according to §63.7910(b)(1), you must meet requirements in paragraphs (a)(1) and (2) of this section.

(1) Measure the seal gaps at least annually according to the requirements in §63.1047(b)(1).

(2) Visually inspect the floating roof at least annually according to the requirements in §63.1047(b)(2).

(b) If you use a cover vented to a control device according to §63.7910(b)(1) or (2), you must meet requirements in paragraphs (b)(1) and (2) of this section.

(1) You must visually inspect the cover and its closure devices for defects according to the requirements in §63.1047(c).

(2) You must monitor and inspect the closed vent system and control device according to the requirements in §63.7927 that apply to you.

(c) If you use a pressurized separator that operates as a closed system according to §63.7910(b)(3), you must visually inspect each pressurized separator and closure devices for defects at least annually to ensure they are operating according to the design requirements in §63.1045(b).

§ 63.7913 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for separators?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7910 applicable to your affected separators by meeting the requirements in paragraphs (b) through (d) of this section as applicable to your surface impoundments.

(b) You must demonstrate continuous compliance for each separator using a floating roof according to §63.7910(b)(1) by meeting the requirements in paragraphs (b)(1) through (6) of this section.

(1) Operating and maintaining the floating roof according to the requirements in §63.1043(b).

(2) Performing seal gap measurement inspections at least annually according to the requirements in §63.1047(b)(1).

(3) Visually inspecting the floating roof at least annually according to the requirements in §63.1047(b)(2).

(4) Repairing defects according to the requirements in §63.1047(d).

(5) Recording the information specified in §63.1048(a) and (b).

(6) Keeping records to document compliance with the requirements according to the requirements in §63.7952.

(c) You must demonstrate continuous compliance for each separator using a fixed roof vented through a closed vent system to a control device according to §63.7910(b)(2) by meeting the requirements in paragraphs (c)(1) through (6) of this section.

(1) Operating and maintaining the fixed roof and its closure devices according to the requirements in §63.1042.

(2) Performing visual inspections of the fixed roof and its closure devices for defects at least annually according to the requirements in §63.1047(a).

(3) Repairing defects according to the requirements in §63.1047(d).

(4) Recording the information specified in §63.1048(a).

(5) Meeting each applicable requirement for demonstrating continuous compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7928.

(6) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(d) You must demonstrate continuous compliance for each pressurized separator operated as a closed system according to §63.7910(b)(3) by meeting the requirements in paragraphs (d)(1) and (2) of this section.

(1) Operating the pressurized separator at all times according to the requirements in §63.1045.

(2) Visually inspecting each pressurized tank and closure devices for defects at least annually to ensure they are operating according to the design requirements in §63.1045(b), and recording the results of each inspection.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69017, Nov. 29, 2006]

Transfer Systems

§ 63.7915 What emissions limitations and work practice standards must I meet for transfer systems?

(a) You must control HAP emissions from each new and existing transfer system subject to §63.7886(b)(1)(v) according to emissions limitations and work practice standards in this section that apply to your affected transfer systems.

(b) For each affected transfer system that is an individual drain system as defined in §63.7957, you must install and operate controls according to the requirements in §63.962.

(c) For each affected transfer system that is not an individual drain system as defined in §63.7957, you must use one of the transfer systems specified in paragraphs (c)(1) through (3) of this section.

(1) A transfer system that uses covers according to the requirements in §63.689(d).

(2) A transfer system that consists of continuous hard piping. All joints or seams between the pipe sections must be permanently or semi-permanently sealed (*e.g.* , a welded joint between two sections of metal pipe or a bolted and gasketed flange).

(3) A transfer system that is enclosed and vented through a closed vent system to a control device according to the requirements specified in paragraphs (c)(3)(i) and (ii) of this section.

(i) The transfer system is designed and operated such that an internal pressure in the vapor headspace in the enclosure is maintained at a level less than atmospheric pressure when the control device is operating, and

(ii) The closed vent system and control device are designed and operated to meet the emissions limitations and work practice standards in §63.7925 that apply to your closed vent system and control device.

(d) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your transfer systems. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

§ 63.7916 How do I demonstrate initial compliance with the emissions limitations and work practice standards for transfer systems?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7915 that apply to your affected transfer systems by meeting the requirements in paragraphs (b) through (e) of this section, as applicable to your transfer systems.

(b) You must demonstrate initial compliance of each individual drain system using controls according to §63.7915(b) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(1) through (3) of this section.

(1) You have installed air emission controls for each individual drain system and junction box according to the requirements in §63.962(a) and (b), and you have records documenting the installation and design.

(2) You will operate the air emission controls according to the requirements in §63.962(b)(5).

(3) You have performed an initial visual inspection of each individual drain system according to the requirements in §63.964(a), and you have records documenting the inspection results.

(c) You must demonstrate initial compliance of each transfer system using covers according to §63.7915(c)(1) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(1) through (3) of this section.

(1) Each transfer system is equipped with covers and closure devices according to the requirements in §63.689(d)(1) through (4), and you have records documenting the design and installation.

(2) You have performed an initial inspection of each cover and its closure devices for defects according to the requirements in §63.695(d)(1) through (5), and you have records documenting the inspection results.

(3) You will operate each cover and its closure devices according to the requirements in §63.689(5).

(d) You must demonstrate initial compliance of each transfer system that consists of hard piping according to §63.7915(c)(2) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (d)(1) and (2) of this section.

(1) You have installed a transfer system that consists entirely of hard piping and meets the requirements in §63.7915(c)(2), and you have records documenting the design and installation.

(2) You have performed an initial inspection of the entire transfer system to verify that all joints or seams between the pipe sections are permanently or semi-permanently sealed (*e.g.,* a welded joint between two sections of metal pipe or a bolted and gasketed flange), and you have records documenting the inspection results.

(e) You must demonstrate initial compliance of each transfer system that is enclosed and vented to a control device according to §63.7915(e)(3) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (e)(1) and (2) of this section.

(1) You have installed a transfer system that is designed and operated such that an internal pressure in the vapor headspace in the enclosure is maintained at a level less than atmospheric pressure when the control device is operating, and you have records documenting the design and installation.

(2) You have met each applicable requirement for demonstrating initial compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7926.

§ 63.7917 What are my inspection and monitoring requirements for transfer systems?

(a) If you operate an individual drain system as a transfer system according to §63.7915(b), you must visually inspect each individual drain system at least annually according to the requirements in §63.964(a).

(b) If you operate a transfer system using covers according to §63.7915(c)(1), you must inspect each cover and its closure devices for defects according to the requirements in §63.695(d)(1) through (5).

(c) If you operate a transfer system consisting of hard piping according to §63.7915(c)(2), you must annually inspect the unburied portion of pipeline and all joints for leaks and other defects. In the event that a defect is detected, you must repair the leak or defect according to the requirements of paragraph (e) of this section.

(d) If you operate a transfer system that is enclosed and vented to a control device according to §63.7915(c)(3), you must meet requirements in paragraphs (d)(1) and (2) of this section.

(1) You must annually inspect all enclosure components (e.g., enclosure sections, closure devices, fans) for defects that would prevent an internal pressure in the vapor headspace in the enclosure from continuously being maintained at a level less than atmospheric pressure when the control device is operating. In the event that a defect is detected, you must repair the defect according to the requirements of paragraph (e) of this section.

(2) You must monitor and inspect the closed vent system and control device according to the requirements in §63.7927 that apply to you.

(e) If you are subject to paragraph (c) or (d) of this section, you must repair all detected defects as specified in paragraphs (e)(1) through (3) of this section.

(1) You must make first efforts at repair of the defect no later than 5 calendar days after detection and repair shall be completed as soon as possible but no later than 45 calendar days after detection except as provided in paragraph (e)(2) of this section.

(2) Repair of a defect may be delayed beyond 45 calendar days if you determine that repair of the defect requires emptying or temporary removal from service of the transfer system and no alternative transfer system is available at the site to accept the material normally handled by the system. In this case, you must repair the defect the next time the process or unit that is generating the material handled by the transfer system stops operation. Repair of the defect must be completed before the process or unit resumes operation.

(3) You must maintain a record of the defect repair according to the requirements specified in §63.7952.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

§ 63.7918 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for transfer systems?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7915 applicable to your affected transfer system by meeting the requirements in paragraphs (b) through (e) of this section as applicable to your transfer systems.

(b) You must demonstrate continuous compliance for each individual drain system using controls according to §63.7915(b) by meeting the requirements in paragraphs (b)(1) through (5) of this section.

(1) Operating and maintaining the air emission controls for individual drain systems according to the requirements in §63.962.

(2) Visually inspecting each individual drain system at least annually according to the requirements in §63.964(a).

(3) Repairing defects according to the requirements in §63.964(b).

(4) Recording the information specified in §63.965(a).

(5) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(c) You must demonstrate continuous compliance for each transfer system using covers according to §63.7915(c)(1) by meeting the requirements in paragraphs (c)(1) through (4) of this section.

(1) Operating and maintaining each cover and its closure devices according to the requirements in §63.689(d)(1) through (5).

(2) Performing inspections of each cover and its closure devices for defects at least annually according to the requirements in §63.695(d)(1) through (5).

(3) Repairing defects according to the requirements in §63.695(5)

(4) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(d) You must demonstrate continuous compliance for each transfer system that consists of hard piping according to §63.7915(c)(2) by meeting the requirements in paragraphs (d)(1) through (4) of this section.

(1) Operating and maintaining the pipeline to ensure that all joints or seams between the pipe sections remain permanently or semi-permanently sealed (*e.g.* , a welded joint between two sections of metal pipe or a bolted and gasketed flange).

(2) Inspecting the pipeline for defects at least annually according to the requirements in §63.7917(c).

(3) Repairing defects according to the requirements in §63.7917(e).

(4) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(e) You must demonstrate continuous compliance for each transfer system that is enclosed and vented to a control device according to §63.7915(c)(3) by meeting the requirements in paragraphs (e)(1) through (5) of this section.

(1) Operating and maintaining the enclosure to ensure that the internal pressure in the vapor headspace in the enclosure is maintained continuously at a level less than atmospheric pressure when the control device is operating.

(2) Inspecting the enclosure and its closure devices for defects at least annually according to the requirements in §63.7918(d).

(3) Repairing defects according to the requirements in §63.7918(e).

(4) Meeting each applicable requirement for demonstrating continuous compliance with the emission limitations and work practice standards for a closed vent system and control device in §63.7928.

(5) Keeping records to document compliance with the requirements according to the requirements in §63.7952.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

Equipment Leaks

§ 63.7920 What emissions limitations and work practice standards must I meet for equipment leaks?

(a) You must control HAP emissions from each new and existing equipment subject to §63.7887 according to emissions limitations and work practice standards in this section that apply to your affected equipment.

(b) For your affected equipment, you must meet the requirements in either paragraph (b)(1) or (2) of this section.

(1) Control equipment leaks according to all applicable requirements under 40 CFR part 63, subpart TT—National Emission Standards for Equipment Leaks—Control Level 1; or

(2) Control equipment leaks according to all applicable requirements under 40 CFR part 63, subpart UU—National Emission Standards for Equipment Leaks—Control Level 2.

(c) If you use a closed vent system and control device to comply with this section, as an alternative to meeting the standards in §63.1015 or §63.1034 for closed vent systems and control devices, you may elect to meet the requirements in §§63.7925 through 63.7928 that apply to your closed vent system and control device.

(d) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your equipment. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

§ 63.7921 How do I demonstrate initial compliance with the emissions limitations and work practice standards for equipment leaks?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in §63.7920 that apply to your affected equipment by meeting the requirements in paragraphs (b) and (c) of this section, as applicable to your affected sources.

(b) If you control equipment leaks according to the requirements under §63.7920(b)(1), you must demonstrate initial compliance if you have met the requirements in paragraphs (b)(1) and (2) of this section.

(1) You include the information required in §63.1018(a)(1) in your notification of compliance status report.

(2) You have submitted as part of your notification of compliance status a signed statement that:

(i) You will meet the requirements in §§63.1002 through 63.1016 that apply to your affected equipment.

(ii) You have identified the equipment subject to control according to the requirements in §63.1003, including equipment designated as unsafe to monitor, and have records supporting the determinations with a written plan for monitoring the equipment according to the requirements in §63.1003(c)(4).

(c) If you control equipment leaks according to the requirements under §63.7920(b)(2), you must demonstrate initial compliance if you have met the requirements in paragraphs (c)(1) and (2) of this section.

(1) You have included the information required in §63.1039(a) in your notification of compliance status report.

(2) You have submitted as part of your notification of compliance status a signed statement that:

(i) You will meet the requirements in §§63.1021 through 63.1037 that apply to your affected equipment.

(ii) You have identified the equipment subject to control according to the requirements in §63.1022, including equipment designated as unsafe to monitor, and have records supporting the determinations with a written plan for monitoring the equipment according to the requirements in §63.1022(c)(4).

§ 63.7922 How do I demonstrate continuous compliance with the work practice standards for equipment leaks?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in §63.7920 applicable to your affected equipment by meeting the requirements in paragraphs (b) through (d) of this section that apply to you.

(b) If you control equipment leaks according to the requirements under §63.7920(b)(1), you must demonstrate continuous compliance by inspecting, monitoring, repairing, and maintaining records according to the requirements in §§63.1002 through 63.1018 that apply to your affected equipment.

(c) If you control equipment leaks according to the requirements under §63.7920(b)(2), you must demonstrate continuous compliance by inspecting, monitoring, repairing, and maintaining records according to the requirements in §§63.1021 through 63.1039 that apply to your affected equipment.

(d) You must keep records to demonstrate compliance with the requirements according to the requirements in §63.7952.

Closed Vent Systems and Control Devices

§ 63.7925 What emissions limitations and work practice standards must I meet for closed vent systems and control devices?

(a) For each closed-vent system and control device you use to comply with requirements in §§63.7890 through 63.7922, as applicable to your affected sources, you must meet the emissions limitations and work practice standards in this section.

(b) Whenever gases or vapors containing HAP are vented through the closed-vent system to the control device, the control device must be operating except at those times listed in either paragraph (b)(1) or (2) of this section.

(1) The control device may be bypassed for the purpose of performing planned routine maintenance of the closed-vent system or control device in situations when the routine maintenance cannot be performed during periods that the emission point vented to the control device is shutdown. On an annual basis, the total time that the closed-vent system or control device is bypassed to perform routine maintenance must not exceed 240 hours per each calendar year.

(2) The control device may be bypassed for the purpose of correcting a malfunction of the closed-vent system or control device. You must perform the adjustments or repairs necessary to correct the malfunction as soon as practicable after the malfunction is detected.

(c) For each closed vent system, you must meet the work practice standards in §63.693(c).

(d) For each control device other than a flare or a control device used to comply with the facility-wide process vent emission limits in §63.7890(b), you must control HAP emissions to meet either of the emissions limits in paragraphs (d)(1) or (2) of this section except as provided for in paragraph (f) of this section.

(1) Reduce emissions of total HAP listed in Table 1 of this subpart or TOC (minus methane and ethane) from each control device by 95 percent by weight; or

(2) Limit the concentration of total HAP listed in Table 1 of this subpart or TOC (minus methane and ethane) from each combustion control device (a thermal incinerator, catalytic incinerator, boiler, or process heater) to 20 ppmv or less on a dry basis corrected to 3 percent oxygen.

(e) If you use a flare for your control device, then you must meet the requirements for flares in §63.11(b).

(f) If you use a process heater or boiler for your control device, then as alternative to meeting the emissions limits in paragraph (d) of this section you may choose to comply with one of the work practice standards in paragraphs (f)(1) through (3) of this section.

(1) Introduce the vent stream into the flame zone of the boiler or process heater and maintain the conditions in the combustion chamber at a residence time of 0.5 seconds or longer and at a temperature of 760 °C or higher; or

(2) Introduce the vent stream with the fuel that provides the predominate heat input to the boiler or process heater (*i.e.,* the primary fuel); or

(3) Introduce the vent stream to a boiler or process heater for which you either have been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H—Hazardous Waste Burned in Boilers and Industrial Furnaces; or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(g) For each control device other than a flare, you must meet each operating limit in paragraphs (g)(1) through (6) of this section that applies to your control device.

(1) If you use a regenerable carbon adsorption system, you must:

(i) Maintain the hourly average total regeneration stream mass flow during the adsorption bed regeneration cycle greater than or equal to the stream mass flow established in the design evaluation or performance test.

(ii) Maintain the hourly average temperature of the adsorption bed during regeneration (except during the cooling cycle) greater than or equal to the temperature established during the design evaluation or performance test.

(iii) Maintain the hourly average temperature of the adsorption bed after regeneration (and within 15 minutes after completing any cooling cycle) less than or equal to the temperature established during the design evaluation.

(iv) Maintain the frequency of regeneration greater than or equal to the frequency established during the design evaluation.

(2) If you use a nonregenerable carbon adsorption system, you must maintain the hourly average temperature of the adsorption bed less than or equal to the temperature established during the design evaluation or performance test.

(3) If you use a condenser, you must maintain the daily average condenser exit temperature less than or equal to the temperature established during the design evaluation or performance test.

(4) If you use a thermal incinerator, you must maintain the daily average firebox temperature greater than or equal to the temperature established in the design evaluation or during the performance test.

(5) If you use a catalytic incinerator, you must maintain the daily average temperature difference across the catalyst bed greater than or equal to the minimum temperature difference established during the performance test or design evaluation.

(6) If you use a boiler or process heater to comply with an emission limit in paragraph (d) of this section, you must maintain the daily average firebox temperature within the operating level established during the design evaluation or performance test.

(h) If you use a carbon adsorption system as your control, you must meet each work practice standard in paragraphs (h)(1) through (3) of this section that applies to your control device.

(1) If you use a regenerable carbon adsorption system, you must:

(i) Replace the existing adsorbent in each segment of the bed with an adsorbent that meets the replacement specifications established during the design evaluation before the age of the adsorbent exceeds the maximum allowable age established during the design evaluation.

(ii) Follow the disposal requirements for spent carbon in §63.693(d)(4).

(2) If you use a nonregenerable carbon adsorption system, you must:

(i) Replace the existing adsorbent in each segment of the bed with an adsorbent that meets the replacement specifications established during the design evaluation before the age of the adsorbent exceeds the maximum allowable age established during the design evaluation.

(ii) Meet the disposal requirements for spent carbon in §63.693(d)(4)(ii).

(3) If you use a nonregenerative carbon adsorption system, you may choose to comply with the requirements in paragraphs (h)(3)(i) and (ii) of this section as an alternative to the requirements in paragraph (h)(2) of this section. You must:

(i) Immediately replace the carbon canister or carbon in the control device when the monitoring device indicates breakthrough has occurred according to the requirements in §63.693(d)(4)(iii)(A), or replace the carbon canister or carbon in the control device at regular intervals according to the requirements in §63.693(d)(4)(iii)(B).

(ii) Follow the disposal requirements for spent carbon in §63.693(d)(4)(ii).

(i) If you use a catalytic incinerator, you must replace the existing catalyst bed with a bed that meets the replacement specifications before the age of the bed exceeds the maximum allowable age established in the design evaluation or during the performance test.

(j) As provided in §63.6(g), you may request approval from the EPA to use an alternative to the work practice standards in this section that apply to your closed vent systems and control devices. If you request for permission to use an alternative to the work practice standards, you must submit the information described in §63.6(g)(2).

§ 63.7926 How do I demonstrate initial compliance with the emission limitations and work practice standards for closed vent systems and control devices?

(a) You must demonstrate initial compliance with the emissions limitations and work practice standards in this subpart applicable to your closed vent system and control device by meeting the requirements in paragraphs (b) through (h) of this section that apply to your closed vent system and control device.

(b) You must demonstrate initial compliance with the closed vent system work practice standards in §63.7925(c) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(1) and (2) of this section.

(1) You have installed a closed vent system that meets the requirements in §63.695(c)(1) and (2), and you have records documenting the equipment design and installation.

(2) You have performed the initial inspection of the closed vent system according to the requirements in §63.695(c)(1)(i) or (ii), and you have records documenting the inspection results.

(c) You must demonstrate initial compliance of each control device subject to the emissions limits in §63.7925(d) with the applicable emissions limit in §63.7925(d) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(1) and (2) of this section that apply to you.

(1) For the emissions limit in §63.7925(d)(1), the emissions of total HAP listed in Table 1 of this subpart or TOC (minus methane and ethane) from the control device, measured or determined according to the procedures for performance tests and design evaluations in §63.7941, are reduced by at least 95 percent by weight.

(2) For the emissions limit in §63.7925(d)(2), the concentration of total HAP listed in Table 1 of this subpart or TOC (minus methane and ethane) from the combustion control device, measured by a performance test or determined by a design evaluation according to the procedures in §63.7941, do not exceed 20 ppmv on a dry basis corrected to 3 percent oxygen.

(d) You must demonstrate initial compliance of each control device subject to operating limits in §63.7925(g) with the applicable limits if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (d)(1) and (2) of this section.

(1) You have established an appropriate operating limit(s) for each of the operating parameter applicable to your control device as specified in §63.7925(g)(1) through (6).

(2) You have a record of the applicable operating parameter data during the performance test or design evaluation during which the emissions met the applicable limit.

(e) You must demonstrate initial compliance with the spent carbon replacement and disposal work practice standards for carbon adsorption systems in §63.7925(h) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you will comply with each work practice standard that applies to your carbon adsorption system.

(f) You must demonstrate initial compliance with the catalyst replacement work practice standards for catalytic incinerators in §63.7925(i) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you will comply with the specified work practice standard.

(g) You must demonstrate initial compliance of each flare with the work practice standards in §63.7925(e) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (g)(1) through (3) of this section.

(1) Each flare meets the requirements in §63.11(b).

(2) You have performed a visible emissions test, determined the net heating value of gas being combusted, and determined the flare exit velocity as required in §63.693(h)(2).

(3) You will operate each flare according to the requirements in §63.11(b).

(h) You must demonstrate initial compliance of each boiler or process heater with the work practice standards in §63.7925(f) if you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (h)(1) through (3) of this section.

(1) For the work practice standards in §63.7925(f)(1), you have records documenting that the boiler or process heater is designed to operate at a residence time of 0.5 seconds or greater and maintain the combustion zone temperature at 760 °C or greater.

(2) For the work practice standard in §63.7925(f)(2), you have records documenting that the vent stream is introduced with the fuel according to the requirements in §63.693(g)(1)(iv), or that the vent stream is introduced to a boiler or process heater that meets the requirements in §63.693(g)(1)(v).

(3) For the work practice standard in §63.7925(f)(3), you have records documenting you either have been issued a final permit under 40 CFR part 270 and your boiler or process heater complies with the requirements of 40 CFR part 266, subpart H—Hazardous Waste Burned in Boilers and Industrial Furnaces; or has been certified in compliance with the interim status requirements of 40 CFR part 266, subpart H.

§ 63.7927 What are my inspection and monitoring requirements for closed vent systems and control devices?

(a) You must comply with the requirements in paragraphs (a)(1) and (2) of this section for each closed vent system.

(1) You must monitor and inspect each closed vent system according to the requirements in either paragraph (a)(1)(i) or (ii) of this section.

(i) You must monitor, inspect, and repair defects according to the requirements in §63.695(c)(1)(ii) through (c)(3); or

(ii) You must monitor and inspect the closed vent system according to the requirements in §63.172(f) through (j) and record the information in §63.181.

(2) If your closed vent system includes a bypass device, you must meet the requirements in either paragraph (a)(2)(i) or (ii) of this section.

(i) Use a flow indicator to determine if the presence of flow according to the requirements in §63.693(c)(2)(i); or

(ii) Use a seal or locking device and make monthly inspections as required by §63.693(c)(2)(ii).

(b) If you use a regenerable carbon adsorption system, you must meet the requirements in paragraphs (b)(1) through (3) of this section.

(1) Use a continuous parameter monitoring system (CPMS) to measure and record the hourly average total regeneration stream mass flow during each carbon adsorption cycle.

(2) Use a CPMS to measure and record the hourly average temperature of the adsorption bed during regeneration (except during the cooling cycle).

(3) Use a CPMS to measure and record the hourly average temperature of the adsorption bed after regeneration (and within 15 minutes after completing any cooling cycle).

(c) If you use a nonregenerable carbon adsorption system, you must use a CPMS to measure and record the hourly average temperature of the adsorption bed or you must monitor the concentration of organic compounds in the exhaust vent stream according to the requirements in §63.693(d)(4)(iii)(A).

(d) If you use a condenser, you must use a CPMS to measure and record the hourly average condenser exit temperature and determine and record the daily average condenser exit temperature.

(e) If you use a thermal incinerator, you must use a CPMS to measure and record the hourly average firebox temperature and determine and record the daily average firebox temperature.

(f) If you use a catalytic incinerator, you must use a CPMS with two temperature sensors to measure and record the hourly average temperature at the inlet of the catalyst bed, the hourly average temperature at the outlet of the catalyst bed, the hourly average temperature difference across the catalyst bed, and to determine and record the daily average temperature difference across the catalyst bed.

(g) If you use a boiler or process heater to meet an emission limitation, you must use a CPMS to measure and record the hourly average firebox temperature and determine and record the daily average firebox temperature.

(h) If you use a flare, you must monitor the operation of the flare using a heat sensing monitoring device according to the requirements in §63.693(h)(3).

(i) If you introduce the vent stream into the flame zone of a boiler or process heater according to the requirements in §63.7925(f)(1), you must use a CPMS to measure and record the combustion zone temperature.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

§ 63.7928 How do I demonstrate continuous compliance with the emissions limitations and work practice standards for closed vent systems and control devices?

(a) You must demonstrate continuous compliance with the emissions limitations and work practice standards in this subpart applicable to your closed vent system and control device by meeting the requirements in paragraphs (b) through (j) of this section as applicable to your closed vent system and control device.

(b) You must demonstrate continuous compliance with the closed vent system work practice standards in §63.7925(c) by meeting the requirements in paragraphs (b)(1) through (7) of this section.

(1) For a closed vent system designed to operate with no detectable organic emissions, visually inspecting the closed vent system at least annually, monitoring after a repair or replacement using the procedures in §63.694(k), and monitoring at least annually according to the requirements in §63.695(c)(1)(ii).

(2) For a closed vent system designed to operate below atmospheric pressure, visually inspecting the closed vent system at least annually according to the requirements in §63.695(c)(2)(ii).

(3) Repairing defects according to the requirements in §63.695(c)(3).

(4) Keeping records of each inspection that include the information in paragraphs (b)(4)(i) through (iii) of this section:

(i) A closed vent system identification number (or other unique identification description you select).

(ii) Date of each inspection.

(iii) If a defect is detected during an inspection, the location of the defect, a description of the defect, the date of detection, the corrective action taken to repair the defect, and if repair is delayed, the reason for any delay and the date completion of the repair is expected.

(5) If you elect to monitor the closed vent system according to the requirements in §63.172(f) through (j), recording the information in §63.181.

(6) If the closed vent system is equipped with a flow indicator, recording the information in §63.693(c)(2)(i).

(7) If the closed vent system is equipped with a seal or locking device, visually inspecting the seal or closure mechanism at least monthly according to the requirements in §63.693(c)(2)(ii), and recording the results of each inspection.

(c) You must demonstrate continuous compliance of each control device subject to the emissions limits in §63.7925(d) with the applicable emissions limit in §63.7925(d) by meeting the requirements in paragraph (c)(1) or (2) of this section.

(1) For the emission limit in §63.7925(d)(1), maintaining the reduction in emissions of total HAP listed in Table 1 of this subpart or TOC (minus methane and ethane) from the control device at 95 percent by weight or greater.

(2) For the emission limit in §63.7925(d)(2), maintaining the concentration of total HAP listed in Table 1 of this subpart or TOC (minus methane and ethane) from the control device at 20 ppmv or less.

(d) You must demonstrate continuous compliance of each control device subject to operating limits in §63.7925(g) with the applicable limits by meeting the requirements in paragraphs (d)(1) through (4) of this section.

(1) Maintaining each operating limit according to the requirements in §63.7925(g) as applicable to the control device.

(2) Monitoring and inspecting each control device according to the requirements in §63.7927(b) through (i) as applicable to the control device.

(3) Operating and maintaining each continuous monitoring system according to the requirements in §63.7945, and collecting and reducing data according to the requirements in §63.7946.

(4) Keeping records to document compliance with the requirements of this subpart according to the requirements in §63.7952.

(e) You must demonstrate continuous compliance with the spent carbon replacement and disposal work practice standards for regenerable carbon adsorption systems in §63.7925(h)(1) by meeting the requirements in paragraphs (e)(1) through (3) of this section.

(1) Replacing the adsorbent as required by §63.7925(h)(1)(i).

(2) Following the disposal requirements for spent carbon in §63.693(d)(4)(ii).

(3) Keeping records to document compliance with the requirements of the work practice standards.

(f) You must demonstrate continuous compliance with the spent carbon replacement and disposal work practice standards for nonregenerable carbon adsorption systems in §63.7925(h)(2) by meeting the requirements in paragraphs (f)(1) through (3) of this section.

(1) Replacing the adsorbent as required by the work practice standard in §63.7925(h)(2)(i).

(2) Following the disposal requirements for spent carbon in §63.693(d)(4)(ii).

(3) Keeping records to document compliance with the requirements of the work practice standards.

(g) You must demonstrate continuous compliance with the spent carbon replacement and disposal work practice standards for nonregenerable carbon adsorption systems in §63.7925(h)(3) by meeting the requirements in paragraphs (g)(1) through (3) of this section.

(1) Monitoring the concentration level of the organic compounds in the exhaust vent for the carbon adsorption system as required in §63.7927(c), immediately replacing the carbon canister or carbon in the control device when breakthrough is indicated by the monitoring device, and recording the date of breakthrough and carbon replacement. Or, you must replace the carbon canister or carbon in the control device at regular intervals and record the date of carbon replacement.

(2) Following the disposal requirements for spent carbon in §63.693(d)(4)(ii).

(3) Keeping records to document compliance with the requirements of the work practice standards.

(h) You must demonstrate continuous compliance with the catalyst replacement work practice standards for catalytic incinerators in §63.7925(i) by meeting the requirements in paragraphs (h)(1) and (2) of this section.

(1) Replacing the existing catalyst bed as required in §63.7925(i).

(2) Keeping records to document compliance with the requirements of the work practice standards.

(i) You must demonstrate continuous compliance of each flare with the work practice standards in §63.7925(e) by meeting the requirements in paragraphs (i)(1) through (5) of this section.

(1) Operating the flare with no visible emissions except for up to 5 minutes in any 2 consecutive hours according to the requirements in §63.11(b)(4).

(2) Monitoring the presence of a pilot flare according to the requirements in §63.7927(h) and maintaining a pilot flame and flare flame at all times that emissions are not vented to the flare according to the requirements in §63.11(b)(5).

(3) Operating the flare with an exit velocity according to the requirements in §63.11(b)(6) through (8).

(4) Operating the flare with a net heating value of the gas being combusted according to the requirements in §63.11(b)(6)(ii).

(5) Keeping records to document compliance with the requirements of the work practice standards.

(j) You must demonstrate continuous compliance of each boiler or process heater with the work practice standards in §63.7925(f) by meeting the requirements in paragraphs (j)(1) through (3) of this section.

(1) For the work practice standards in §63.7925(f)(1), you must demonstrate continuous compliance by meeting the requirements in paragraphs (j)(1)(i) through (iv).

(i) Maintaining conditions in the combustion chamber at a residence time of 0.5 seconds or longer and at a combustion zone temperature at 760 °C or greater whenever the vent stream is introduced to the flame zone of the boiler or process heater.

(ii) Monitoring each boiler or process heater according to the requirements in §63.7927(i).

(iii) Operating and maintaining each continuous monitoring system according to the requirements in §63.7945, and collecting and reducing data according to the requirements in §63.7946.

(iv) Keeping records to document compliance with residence time design requirement.

(2) For the work practice standards in §63.7925(f)(2), you maintain the boiler or process heater operations such that the vent stream is introduced with the fuel according to the requirements in §63.693(g)(1)(iv), or that the vent stream is introduced to a boiler or process heater that meets the requirements in §63.693(g)(1)(v).

(3) For the work practice standard in §63.7925(f)(3), you remain in compliance with all terms and conditions of the final permit under 40 CFR part 270 and your boiler or process heater complies with the requirements of 40 CFR part 266, subpart H—Hazardous Waste Burned in Boilers and Industrial Furnaces; or in compliance with the interim status requirements of 40 CFR part 266, subpart H, as applicable to your boiler or process heater.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

General Compliance Requirements

§ 63.7935 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emissions limitations (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

(b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in §63.6(e)(1)(i).

(c) You must develop a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).

(d) [Reserved]

(e) You must report each instance in which you did not meet each emissions limitation and each operating limit that applies to you. This includes periods of startup, shutdown, and malfunction. You must also report each instance in which you did not meet the requirements for work practice standards that apply to you. These instances are deviations from the emissions limitations and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7951.

(f) Consistent with §§63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with §63.6(e)(1). We will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

(g) For each monitoring system required in this section, you must develop and make available for inspection by the permitting authority, upon request, a site-specific monitoring plan that addresses the following:

(1) Installation of the continuous monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.,* on or downstream of the last control device).

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction system.

(3) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations).

(h) In your site-specific monitoring plan, you must also address the following:

(1) Ongoing operation and maintenance procedures according to the general requirements of §63.8(c)(1), (3), (4)(ii), (7), and (8).

(2) Ongoing data quality assurance procedures according to the general requirements of §63.8(d).

(3) Ongoing recordkeeping and reporting procedures according to the general requirements of §63.10(c), (e)(1), and (e)(2)(i).

(i) You must operate and maintain the continuous monitoring system according to the site-specific monitoring plan.

(j) You must conduct a performance evaluation of each continuous monitoring according to your site-specific monitoring plan.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 20468, Apr. 20, 2006; 71 FR 69018, Nov. 29, 2006]

§ 63.7936 What requirements must I meet if I transfer remediation material off-site to another facility?

(a) If you transfer to another facility a remediation material generated by your remediation activities and having an average total VOHAP concentration equal to or greater than 10 ppmw (as determined using the procedures specified in §63.7943), then you must transfer the remediation material to a facility that meets the requirements in paragraph (b) of this section. You must record the name, street address, and telephone number of the facility where you send this remediation material.

(b) You may elect to transfer the remediation material to one of the following facilities:

(1) A facility where your remediation material will be directly disposed in a landfill or other land disposal unit according to all applicable Federal and State requirements.

(2) A facility subject to 40 CFR part 63, subpart DD where the exemption under §63.680(b)(2)(iii) is waived and air emissions from the management of your remediation material at the facility are controlled according to all applicable requirements in the subpart for an off-site material. Prior to sending your remediation material, you must obtain a written statement from the owner or operator of the facility to which you send your remediation material acknowledging that the exemption under §63.680(b)(2)(iii) will be waived for all remediation material received at the facility from you and your material will be managed as an off-site material at the facility according to all applicable requirements. This statement must be signed by the responsible official of the receiving facility, provide the name and address of the receiving facility, and a copy sent to the appropriate EPA Regional Office at the addresses listed in 40 CFR 63.13.

(3) A facility where your remediation material will be managed according to all applicable requirements under this Subpart.

(i) You must prepare and include a notice with each shipment or transport of remediation material from your site. This notice must state that the remediation material contains organic HAP that are to be treated according to the provisions of this subpart. When the transport is continuous or ongoing (for example, discharge to a publicly owned treatment works), the notice must be submitted to the receiving facility owner or operator initially and whenever there is a change in the required treatment.

(ii) You may not transfer the remediation material unless the owner or operator of the facility receiving your remediation material has submitted to the EPA a written certification that he or she will manage remediation material received from you according to the requirements of §§63.7885 through 63.7957. The receiving facility owner or operator may revoke the written certification by sending a written statement to the EPA and to you providing at least 90 days notice that they rescind acceptance of responsibility for compliance with the regulatory provisions listed in this section. Upon expiration of the notice period, you may not transfer your remediation material to the facility.

(iii) By providing the written certification to the EPA, the receiving facility owner or operator accepts responsibility for compliance with the regulatory provisions listed in paragraph (b)(3) of this section with respect to any shipment of remediation material covered by the written certification. Failure to abide by any of those provisions with respect to such shipments may result in enforcement action by the EPA against the certifying entity according to the enforcement provisions applicable to violations of these provisions by owners or operators of sources.

(iv) Written certifications and revocation statements to the EPA from the receiving facility owner or operator must be signed by the responsible official of the receiving facility, provide the name and address of the receiving facility, and a copy sent to the appropriate EPA Regional Office at the addresses listed in 40 CFR 63.13. Such written certifications are not transferable.

(c) Acceptance by a facility owner or operator of remediation material from a site remediation subject to this Subpart does not, by itself, require the facility owner or operator to obtain a title V permit under 40 CFR 70.3 or 40 CFR 71.3.

§ 63.7937 How do I demonstrate initial compliance with the general standards?

(a) You must demonstrate initial compliance with the general standards in §§63.7884 through 63.7887 that apply to your affected sources by meeting the requirements in paragraphs (b) through (d) of this section, as applicable to you.

(b) You must demonstrate initial compliance with the general standards in §63.7885 that apply to your affected process vents by meeting the requirements in paragraphs (b)(1) through (4) of this section, as applicable to your process vents.

(1) If HAP emissions are controlled from the affected process vents according to the emission limitations and work practice standards specified in §63.7885(b)(1), you have met the initial compliance requirements in §63.7891.

(2) If the remediation material treated or managed by the process vented through the affected process vents has an average total VOHAP less than 10 ppmw according to §63.7885(b)(2), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have determined, according to the procedures §63.7943, and recorded the average VOHAP concentration of the remediation material placed in the affected remediation material management unit.

(3) If HAP emissions are controlled from the affected process vents to meet standards in another subpart under 40 CFR part 61 or 40 CFR part 63 according to §63.7885(b)(3), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(3)(i) and (ii) of this section.

(i) You include in your statement the citations for the specific emission limitations and work practice standards that apply to the process vents under the subpart in 40 CFR part 61 or 40 CFR part 63 that the vents are also subject.

(ii) You are complying with all applicable emissions limitations and work practice standards specified by the applicable subpart.

(4) For each process vent exempted according to §63.7885(c), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (b)(4)(i) and (ii) of this section.

(i) You identify in your statement each process vent that qualifies for an exemption and the exemption conditions in §63.7885(c)(1)(i) or (ii) that apply to each exempted process vent.

(ii) You have performed the measurements and prepared the documentation required in §63.7885(c)(2) that demonstrates that each exempted process vent stream meets the applicable exemption conditions in §63.7885(c)(1).

(c) You must demonstrate initial compliance with the general standards in §63.7886 that apply to your affected remediation material management units by meeting the requirements in paragraphs (c)(1) through (6) of this section, as applicable to your remediation material management units.

(1) If the remediation material management unit uses air pollution controls according to the standards specified in §63.7886(b)(1), you have met the initial compliance requirements applicable to the remediation material management unit in §§63.7896, 63.7901, 63.7906, 63.7911, or 63.7816.

(2) If the remediation material managed in the affected remediation material management unit has an average total VOHAP concentration less than 500 ppmw according to §63.7886(b)(2), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have determined, according to the procedures in §63.7943, and recorded the average VOHAP concentration of the remediation material placed in the affected remediation material management unit.

(3) If HAP emissions are controlled from the affected remediation material management units to meet standards in another subpart under 40 CFR part 61 or 40 CFR part 63 according to §63.7886(b)(3), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(3)(i) and (ii) of this section.

(i) You include in your statement the citations for the specific emission limitations and work practice standards that apply to the remediation material management units under the subpart in 40 CFR part 61 or 40 CFR part 63 that the units are also subject.

(ii) You are complying with all applicable emissions limitations and work practice standards specified by the applicable subpart.

(4) If HAP emissions are controlled from the affected remediation material management unit that is an open tank or surface impoundment used for a biological treatment process according to §63.7886(b)(4), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(4)(i) and (ii) of this section.

(i) You have performed the measurements and prepared the documentation required in §63.7886(b)(4)(i) that demonstrates that each unit meets the applicable performance levels.

(ii) You will monitor the biological treatment process conducted in each unit according to the requirements in §63.684(e)(4).

(5) For each remediation material management unit used for cleanup of radioactive mixed waste and exempted according to §63.7886(c), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(5)(i) and (ii) of this section.

(i) You include in your statement the citations for the specific requirements that apply to the remediation material management units under regulations, directives, and other requirements under the Atomic Energy Act, the Nuclear Waste Policy Act, or the Waste Isolation Pilot Plant Land Withdrawal Act.

(ii) You are complying with all requirements that apply to the remediation material management units under the applicable regulations or directives.

(6) For each remediation material management unit exempted according to §63.7886(d), you have submitted as part of your notification of compliance status, specified in §63.7950, a signed statement that you have met the requirements in paragraphs (c)(6)(i) and (ii) of this section.

(i) You have designated according to the requirements in §63.7886(d)(1) each of the remediation material management units you are selecting to be exempted.

(ii) You have performed an initial determination and prepared the documentation required in §63.7886(d)(2) that demonstrates that the total annual HAP quantity (based on the HAP listed in Table 1 of this subpart) in the remediation material placed in all of the designated exempted remediation material management units will be less than 1 Mg/yr.

(d) You must demonstrate initial compliance with the general standards in §63.7887 that apply to your affected equipment leak sources by meeting the requirements in §63.7921.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

§ 63.7938 How do I demonstrate continuous compliance with the general standards?

(a) You must demonstrate continuous compliance with the general standards in §§63.7884 through 63.7887 that apply to your affected sources by meeting the requirements in paragraphs (b) through (d) of this section, as applicable to you.

(b) You have demonstrated continuous compliance with the general standards in §63.7885 that apply to your affected process vents by meeting the requirements in paragraphs (b)(1) through (4) of this section, as applicable to your process vents.

(1) If HAP emissions are controlled from the affected process vents according to the emission limitations and work practice standards specified in §63.7885(b)(1), you must demonstrate continuous compliance by meeting the requirements in §63.7893.

(2) If the remediation material treated or managed by the process vented through the affected process vents has an average total VOHAP less than 10 ppmw according to §63.7885(c)(1), you must demonstrate continuous compliance by performing a new determination and preparing new documentation as required in §63.7885(c)(2) to show that the total VOHAP concentration of the remediation material remains less than 10 ppmw.

(3) If HAP emissions are controlled from the affected process vents to meet standards in another subpart under 40 CFR part 61 or 40 CFR part 63 according to §63.7885(b)(3), you must demonstrate continuous compliance by complying with all applicable emissions limitations and work practice standards specified by the applicable subpart.

(4) For each process vent exempted according to §63.7885(c), you must demonstrate continuous compliance by performing new measurements and preparing new documentation as required in §63.7885(c)(2) that demonstrates that each exempted process vent stream meets the applicable exemption conditions in §63.7885(c)(1).

(c) You must demonstrate continuous compliance with the general standards in §63.7886 that apply to your affected remediation material management units by meeting the requirements in paragraphs (c)(1) through (6) of this section, as applicable to your remediation material management units.

(1) If the remediation material management unit uses air pollution controls according to the standards specified in §63.7886(b)(1), you must demonstrate continuous compliance by meeting the requirements applicable to the remediation material management unit in §§63.7898, 63.7903, 63.7908, 63.7913, or 63.7818.

(2) If the remediation material managed in the affected remediation material managements has an average total VOHAP concentration less than 500 ppmw according to §63.7886(b)(2), you must demonstrate continuous compliance by performing a new determination and preparing new documentation as required in §63.7886(c)(2) to show that the total VOHAP concentration of the remediation material remains less than 500 ppmw.

(3) If HAP emissions are controlled from the affected remediation material management units to meet standards in another subpart under 40 CFR part 61 or 40 CFR part 63 according to §63.7886(b)(3), you must demonstrate continuous compliance by meeting all applicable emissions limitations and work practice standards specified by the applicable subpart.

(4) If HAP emissions are controlled from the affected remediation material management unit that is an open tank or surface impoundment used for a biological treatment process according to §63.7886(b)(4), you must demonstrate continuous compliance by meeting the requirements in paragraphs (c)(4)(i) and (ii) of this section.

(i) Performing new measurements and preparing new documentation as required in §63.7886(4)(i) that demonstrates that each unit meets the applicable performance levels.

(ii) Monitoring the biological treatment process conducted in each unit according to the requirements in §63.7886(4)(i).

(5) For each remediation material management unit used for cleanup of radioactive mixed waste and exempted according to §63.7886(c), you must demonstrate continuous compliance by meeting all requirements that apply to the remediation material management units under the applicable regulations or directives.

(6) For each remediation material management unit exempted according to §63.7886(d), you must demonstrate continuous compliance by performing new measurements and preparing new documentation as required in §63.7886(d)(2) to show that the total annual HAP quantity (based on the HAP listed in Table 1 of this subpart) in the remediation material placed in all of the designated exempted remediation material management units remains less than 1 Mg/yr.

(d) You have demonstrated continuous compliance with the general standards in §63.7887 that apply to your affected equipment leak sources by meeting the requirements in §63.7923.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69018, Nov. 29, 2006]

Performance Tests

§ 63.7940 By what date must I conduct performance tests or other initial compliance demonstrations?

(a) You must conduct a performance test or design evaluation for each existing affected source within 180 calendar days after the compliance date that is specified in §63.7883.

(b) For each work practice standard that applies to you where initial compliance is not demonstrated using a performance test or design evaluation, you must demonstrate initial compliance within 30 calendar days after the compliance date that is specified in §63.7883 for your affected source.

(c) For new sources, you must conduct initial performance tests and other initial compliance demonstrations according to the provisions in §63.7(a)(2).

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69019, Nov. 29, 2006]

§ 63.7941 How do I conduct a performance test, design evaluation, or other type of initial compliance demonstration?

(a) You must conduct a performance test or design evaluation to demonstrate initial compliance for each new or existing affected source that is subject to an emission limit in this subpart. You must report the results of the performance test or design evaluation according to the requirements in §63.7950(e)(1).

(b) If you choose to conduct a performance test to demonstrate initial compliance, you must conduct the test according to the requirements in §63.7(e)(1) and paragraphs (b) (1) through (5) of this section.

(1) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(2) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).

(3) You must conduct each performance test using the test methods and procedures in §63.694(l).

(4) Follow the procedures in paragraphs (b)(4)(i) through (iii) of this section to determine compliance with the facility-wide total organic mass emissions rate in §63.7890(a)(1)(i).

(i) Determine compliance with the total organic mass flow rate using Equation 1 of this section as follows:

$$E_h = \left(0.0416 \times 10^{-6}\right) Q_{sd} \sum_{i=1}^{n} \left(C_i \times MW_i\right) \qquad \text{(Eq. 1)}$$

Where:

E_h= Total organic mass flow rate, kg/h;

Q_{sd}= Volumetric flow rate of gases entering or exiting control device (or exiting the process vent if no control device is used), as determined by Method 2 of 40 CFR part 60, appendix A, dscm/h;

n = Number of organic compounds in the vent gas;

C_i= Organic concentration in ppm, dry basis, of compound i in the vent gas, as determined by Method 18 of 40 CFR part 60, appendix A;

MW_i= Molecular weight of organic compound i in the vent gas,kg/kg-mol;

(ii) Determine compliance with the annual total organic emissions rate using Equation 2 of this section as follows:

$$E_A = E_h \times H \qquad \text{(Eq. 2)}$$

Where:

E_A= Total organic mass emissions rate, kilograms per year;

E_h= Total organic mass flow rate for the process vent, kg/h;

H = Total annual hours of operation for the affected unit, h.

(iii) Determine compliance with the total organic emissions limit from all affected process vents at the facility by summing the total hourly organic mass emissions rates ($E_h$as determined in Equation 1 of this section) and summing the total annual organic mass emissions rates (E_A, as determined in Equation 2 of this section) for all affected process vents at the facility.

(5) Determine compliance with the 95 percent reduction limit in §63.7890(a)(2)(i) for the combination of all affected process vents at the facility using Equations 3 and 4 of this section to calculate control device inlet and outlet concentrations and Equation 5 of this section to calculate control device emission reductions for process vents as follows:

$$E_i = K_2 \left(\sum_{j=1}^{n} C_{ij} M_{ij} \right) Q_i \qquad (Eq.\ 3)$$

$$E_o = K_2 \left(\sum_{j=1}^{n} C_{oj} M_{oj} \right) Q_o \qquad (Eq.\ 4)$$

Where:

C_{ij}, C_{oj}= Concentration of sample component j of the gas stream at the inlet and outlet of the control device, dry basis, parts per million by volume. For uncontrolled vents, C_{ij}= $C_{oj}$and equal the concentration exiting the vent;

E_i, E_o= Mass rate of total organic compounds (TOC) (minus methane and ethane) or total HAP, from Table 1 of this subpart, at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour. For uncontrolled vents, E_i= $E_o$and equal the concentration exiting the vent;

M_{ij}, M_{oj}= Molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole. For uncontrolled vents, M_{ij}= $M_{oj}$and equal the gas stream molecular weight exiting the vent;

Q_i, Q_o= Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meters per minute (dscm/min). For uncontrolled vents, Q_i= $Q_o$and equals the flowrate exiting the vent;

K_2= Constant, 2.494×10^{-6}(parts per million)$^{-1}$(gram-mole per standard cubic meter)(kilogram/gram)(minute/hour, where standard temperature (gram-mole per standard cubic meter) is 20 °C);

n = the number of components in the sample.

$$R_v = \frac{\sum_{j=1}^{n} E_i - \sum_{j=1}^{n} E_o}{\sum_{j=1}^{n} E_i} \times 100 \qquad (Eq.\ 5)$$

Where:

R_v= Overall emissions reduction for all affected process vents, percent

E_i= Mass rate of TOC (minus methane and ethane) or total HAP, from Table 1 of this subpart, at the inlet to the control device, or exiting the vent for uncontrolled vents, as calculated in this section, kilograms TOC per hour or kilograms HAP per hour;

E_o= Mass rate of TOC (minus methane and ethane) or total HAP, from Table 1 of this subpart, at the outlet to the control device, or exiting the vent for uncontrolled vents, as calculated in this section, kilograms TOC per hour or kilograms HAP per hour. For vents without a control device, E_o= E_i;

n = number of affected source process vents.

(c) If you use a carbon adsorption system, condenser, vapor incinerator, boiler, or process heater to meet an emission limit in this subpart, you may choose to perform a design evaluation to demonstrate initial compliance instead of a performance test. You must perform a design evaluation according to the general requirements in §63.693(b)(8) and the specific requirements in §63.693(d)(2)(ii) for a carbon adsorption system (including establishing carbon replacement schedules and associated requirements), §63.693(e)(2)(ii) for a condenser, §63.693(f)(2)(ii) for a vapor incinerator, or §63.693(g)(2)(i)(B) for a boiler or process heater.

(d) During the performance test or design evaluation, you must collect the appropriate operating parameter monitoring system data, average the operating parameter data over each test run, and set operating limits, whether a minimum or maximum value, based on the average of values for each of the three test runs. If you use a control device design analysis to demonstrate control device performance, then the minimum or maximum operating parameter value must be established based on the control device design analysis and supplemented, as necessary, by the control device manufacturer recommendations or other applicable information.

(e) If you control air emissions from an affected source by introducing the vent stream into the flame zone of a boiler or process heater according to the requirements in §63.693(g)(1)(iii), you must conduct a performance test or design evaluation to demonstrate that the boiler or process heater meets the applicable emission limit while operating at a residence time of 0.5 seconds or greater and at a combustion zone temperature of 760 °C or higher.

(f) You must conduct a performance evaluation for each continuous monitoring system according to the requirements in §63.8(e).

(g) If you are required to conduct a visual inspection of an affected source, you must conduct the inspection according to the procedures in §63.906(a)(1) for Tank Level 1 controls, §63.1063(d) for Tank Level 2 controls, §63.926(a) for Container Level 1 controls, §63.946(a) for a surface impoundment equipped with a floating membrane cover, §63.946(b) for a surface impoundment equipped with a cover and vented to a control device, §63.1047(a) for a separator with a fixed roof, §63.1047(c) for a separator equipped with a fixed roof and vented to a control device, §63.695(c)(1)(i) or (c)(2)(i) for a closed vent system, and §63.964(a) for individual drain systems.

(h) [Reserved]

(i) If you use Container Level 2 controls, you must conduct a test to demonstrate that the container operates with no detectable organic emissions or that the container is vapor-tight. You must conduct the test using Method 21 (40 CFR part 60, appendix A) and the procedures in §63.925(a) to demonstrate that the container operates with no detectable organic emissions or Method 27 (40 CFR part 60, appendix A) and the procedures in §63.925(b) to demonstrate that the container is vapor-tight.

(j) If you locate an affected source inside a permanent total enclosure that is vented to a control device, you must demonstrate that the enclosure meets the verification criteria in section 5 of Procedure T in 40 CFR 52.741, appendix B.

(k) If you use a fixed roof or a floating roof to control air emissions from a separator, you must conduct a test to demonstrate that the roof operates with no detectable organic emissions using Method 21 (40 CFR part 60, appendix A) and the procedures in §63.1046(a). If you use a floating roof, you also must measure the seal gaps according to the procedures in §63.1046(b).

(l) If you use a flare to control air emissions, you must conduct a visible emissions test using Method 22 in 40 CFR part 60, appendix A, and the procedures in §63.11(b)(4).

(m) For each initial compliance demonstration that requires a performance test or design evaluation, you must report the results in your notification of compliance status according to the requirements in §63.7950(e)(1). For each initial compliance demonstration that does not require a performance test or design evaluation, you must submit a notification of compliance status according to the requirements in §63.7950(e)(2).

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69019, Nov. 29, 2006]

§ 63.7942 When must I conduct subsequent performance tests?

For non-flare control devices, you must conduct performance tests at any time the EPA requires you to according to §63.7(3).

§ 63.7943 How do I determine the average VOHAP concentration of my remediation material?

(a) General requirements. You must determine the average total VOHAP concentration of a remediation material using either direct measurement as specified in paragraph (b) of this section or by knowledge as specified in paragraph (c) of this section. These methods may be used to determine the average VOHAP concentration of any material listed in (a)(1) through (3) of this section.

(1) A single remediation material stream; or

(2) Two or more remediation material streams that are combined prior to, or within, a remediation material management unit or treatment process; or

(3) Remediation material that is combined with one or more non-remediation material streams prior to, or within, a remediation material management unit or treatment process.

(b) Direct measurement. To determine the average total VOHAP concentration of a remediation material using direct measurement, you must use the procedures in paragraphs (b)(1) through (3) of this section.

(1) Sampling. Samples of each material stream must be collected from the container, pipeline, or other device used to deliver each material stream prior to entering the remediation material management unit or treatment process in a manner such that volatilization of organics contained in the sample is minimized and an adequately representative sample is collected and maintained for analysis by the selected method.

(i) The averaging period to be used for determining the average total VOHAP concentration for the material stream on a mass-weighted average basis must be designated and recorded. The averaging period can represent any time interval that you determine is appropriate for the material stream but must not exceed 1 year. For streams that are combined, an averaging period representative for all streams must be selected.

(ii) No less than four samples must be collected to represent the complete range of HAP compositions and HAP quantities that occur in each material stream during the entire averaging period due to normal variations in the material stream(s). Examples of such normal variations are variation of the HAP concentration within a contamination area.

(iii) All samples must be collected and handled according to written procedures you prepare and document in a site sampling plan. This plan must describe the procedure by which representative samples of the material stream(s) are collected such that a minimum loss of organics occurs throughout the sample collection and handling process and by which sample integrity is maintained. A copy of the written sampling plan must be maintained on site in the facility operating records. An example of an acceptable sampling plan includes a plan incorporating sample collection and handling procedures according to the guidance found in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW–846 or Method 25D in 40 CFR part 60, appendix A.

(2) Analysis. Each collected sample must be prepared and analyzed according to either one of the methods listed in §63.694(b)(2)(ii), or any current EPA Contracts Lab Program method (or future revisions) capable of identifying all the HAP in Table 1 of this subpart.

(3) Calculations. The average total VOHAP concentration (C) on a mass-weighted basis must be calculated by using the results for all samples analyzed according to paragraph (b)(2) of this section and Equation 1 of this section as follows:

$$\bar{C} = \frac{1}{Q_T} \times \sum_{i=1}^{n} (Q_i \times C_i) \qquad (Eq.\ 1)$$

Where:

C= Average VOHAP concentration of the material on a mass-weighted basis, ppmw.

i = Individual sample "i" of the material.

n = Total number of samples of the material collected (at least 4 per stream) for the averaging period (not to exceed 1 year).

Q_i= Mass quantity of material stream represented by C_i, kilograms per hour (kg/hr).

Q_T= Total mass quantity of all material during the averaging period, kg/hr.

C_i= Measured VOHAP concentration of sample "i" as determined according to the requirements of paragraph (b)(2) of this section, ppmw.

(c) Knowledge of the material. To determine the average total VOHAP concentration of a remediation material using knowledge, you must use the procedures in paragraphs (c)(1) through (3) of this section.

(1) Documentation must be prepared that presents the information used as the basis for your knowledge of the material stream's average VOHAP concentration. Examples of information that may be used as the basis for knowledge include: material balances for the source(s) generating each material stream; species-specific chemical test data for the material stream from previous testing that are still applicable to the current material stream; test data for material from the contamination area(s) being remediated.

(2) If test data are used as the basis for knowledge, then you must document the test method, sampling protocol, and the means by which sampling variability and analytical variability are accounted for in the determination of the average VOHAP concentration. For example, you may use HAP concentration test data for the material stream that are validated according to Method 301 in 40 CFR part 63, appendix A as the basis for knowledge of the material. This information must be provided for each material stream where streams are combined.

(3) If you use species-specific chemical concentration test data as the basis for knowledge of the material, you may adjust the test data to the corresponding average VOHAP concentration value which would be obtained had the material samples been analyzed using Method 305. To adjust these data, the measured concentration for each individual HAP chemical species contained in the material is multiplied by the appropriate species-specific adjustment factor (f_{m305}) listed in Table 1 of this subpart.

(d) In the event that you and us disagree on a determination using knowledge of the average total VOHAP concentration for a remediation material, then the results from a determination of VOHAP concentration using direct measurement by Method 305 in 40 CFR part 60 appendix A, as specified in paragraph (b) of this section, will be used to determine compliance with the applicable requirements of this subpart. We may perform or request that you perform this determination using direct measurement.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69019, Nov. 29, 2006]

§ 63.7944 How do I determine the maximum HAP vapor pressure of my remediation material?

(a) You must determine the maximum HAP vapor pressure of your remediation material using either direct measurement as specified in paragraph (b) of this section or by knowledge as specified in paragraph (c) of this section.

(b) Direct measurement to determine the maximum HAP vapor pressure.

(1) Sampling. A sufficient number of samples must be collected to be representative of the remediation material contained in the tank. All samples must be collected and handled according to written procedures prepared by you and documented in a site sampling plan. This plan must describe the procedure by which representative samples of the remediation material are collected such that a minimum loss of organics occurs throughout the sample collection and handling process and by which sample integrity is maintained. A copy of the written sampling plan must be maintained on site in the facility site operating records. An example of an acceptable sampling plan includes a plan incorporating sample collection and handling procedures according to the guidance found in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW–846 or Method 25D in 40 CFR part 60, appendix A.

(2) Analysis. Any one of the following methods may be used to analyze the samples and compute the maximum HAP vapor pressure of the remediation material:

(i) Method 25E in 40 CFR part 60 appendix A;

(ii) Methods described in American Petroleum Institute Bulletin 2517, "Evaporation Loss from External Floating Roof Tanks,";

(iii) Methods obtained from standard reference texts;

(iv) ASTM Method 2879–83; or

(v) Any other method approved by the Administrator.

(c) Use of knowledge to determine the maximum HAP vapor pressure. Documentation must be prepared and recorded that presents the information used as the basis for your knowledge that the maximum HAP vapor pressure of the remediation material is less than the maximum vapor pressure limit listed in Table 2 of this subpart for the applicable tank design capacity category.

(d) In the event that you and us disagree on a determination using knowledge of the maximum HAP vapor pressure of the remediation material, then the results from a determination of maximum HAP vapor pressure using direct measurement by Method 25E in 40 CFR part 60 appendix A, as specified in paragraph (b) of this section, will be used to determine compliance with the applicable requirements of this subpart. We may perform or request that you perform this determination using direct measurement.

Continuous Monitoring Systems

§ 63.7945 What are my monitoring installation, operation, and maintenance requirements?

(a) Each CPMS must meet the requirements in paragraphs (a)(1) through (4) of this section.

(1) Complete a minimum of one cycle of operation for each successive 15-minute period.

(2) To calculate a valid hourly value, you must have at least three of four equally spaced data values (or at least two, if that condition is included to allow for periodic calibration checks) for that hour from a CPMS that is not out of control according to the monitoring plan referenced in §63.7935.

(3) To calculate the average emissions for each averaging period, you must have at least 75 percent of the hourly averages for that period using only block hourly average values that are based on valid data (*i.e.,* not from out-of-control periods).

(4) Unless otherwise specified, each CPMS must determine the hourly average of all recorded readings and daily average, if required.

(b) You must record the results of each inspection, calibration, and validation check.

(c) You must conduct a performance evaluation for each CPMS according to the requirements in §63.8(e) and your site-specific monitoring plan.

§ 63.7946 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and your site-specific monitoring plan required in §63.7935.

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, out of control periods and required quality assurance or control activities in data averages and calculations used to report emissions or operating levels, nor may such data be used in fulfilling a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

§ 63.7947 What are my monitoring alternatives?

(a) As an alternative to the parametric monitoring required in this subpart, you may install, calibrate, and operate a continuous emission monitoring system (CEMS) to measure the control device outlet total organic emissions or organic HAP emissions concentration.

(1) The CEMS used on combustion control devices must include a diluent gas monitoring system (for O_2or CO_2) with the pollutant monitoring system in order to correct for dilution (*e.g.,* to 0 percent excess air).

(2) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data must be reduced as specified in §63.8(g)(2).

(3) You must conduct a performance evaluation of the CEMS according to the requirements in §63.8 and Performance Specification 8 (for a total organic emissions CEMS) or Performance Specification 9 (for a HAP emissions CEMS) and Performance Specification 3 (for an O_2or CO_2CEMS) of 40 CFR part 60, appendix B. The relative accuracy provision of Performance Specification 8, sections 2.4 and 3 need not be conducted.

(4) You must prepare a site-specific monitoring plan for operating, calibrating, and verifying the operation of your CEMS according to the requirements in §§63.8(c), (d), and (e).

(5) You must establish the emissions concentration operating limit according to paragraphs (a)(5)(i) and (ii) of this section.

(i) During the performance test, you must monitor and record the total organic or HAP emissions concentration at least once every 15 minutes during each of the three test runs.

(ii) Use the data collected during the performance test to calculate and record the average total organic or HAP emissions concentration maintained during the performance test. The average total organic or HAP emissions concentration, corrected for dilution as appropriate, is the maximum operating limit for your control device.

(b) You must maintain the daily (24-hour) average total organic or HAP emissions concentration in the exhaust vent stream of the control device outlet less than or equal to the site-specific operating limit established during the performance test.

Notification, Reports, and Records

§ 63.7950 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), 63.8(f)(4) and (6), and 63.9(b) through (h) that apply to you.

(b) As specified in §63.9(b)(2), if you start up your affected source before October 8, 2003, you must submit an Initial Notification not later than 120 calendar days after October 8, 2003.

(c) As specified in §63.9(b)(3), if you start up your new or reconstructed affected source on or after the effective date, you must submit an Initial Notification no later than 120 calendar days after initial startup.

(d) If you are required to conduct a performance test, you must submit a notification of intent to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin as required in §63.7(b)(1).

(e) If you are required to conduct a performance test, design evaluation, or other initial compliance demonstration, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration that includes a performance test or design evaluation, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test according to §63.10(d)(2). You must submit the complete design evaluation and supporting documentation.

(2) For each initial compliance demonstration that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th calendar day following the completion of the initial compliance demonstration.

(f) You must provide written notification to the Administrator of the alternative standard selected under §63.1006(b)(5) or (6) before implementing either of the provisions.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69019, Nov. 29, 2006]

§ 63.7951 What reports must I submit and when?

(a) Compliance report due dates. Unless the Administrator has approved a different schedule, you must submit a semiannual compliance report to your permitting authority according to the requirements specified in paragraphs (a)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.7883 and ending on June 30 or December 31, whichever date comes first after the compliance date that is specified for your affected source.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after your first compliance report is due.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of the dates specified in paragraphs (a)(1) through (4) of this section.

(b) Compliance report contents. Each compliance report must include the information specified in paragraphs (b)(1) through (3) of this section and, as applicable, paragraphs (b)(4) through (9) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a startup, shutdown, or malfunction during the reporting period and you took action consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in §63.10(d)(5)(i).

(5) If there were no deviations from any emissions limitations (including operating limit), work practice standards, or operation and maintenance requirements, a statement that there were no deviations from the emissions limitations, work practice standards, or operation and maintenance requirements during the reporting period.

(6) If there were no periods during which a continuous monitoring system (including a CPMS or CEMS) was out-of-control as specified by §63.8(c)(7), a statement that there were no periods during which the CPMS was out-of-control during the reporting period.

(7) For each deviation from an emissions limitation (including an operating limit) that occurs at an affected source for which you are not using a continuous monitoring system (including a CPMS or CEMS) to comply with an emissions limitation or work practice standard required in this subpart, the compliance report must contain the information specified in paragraphs (b)(1) through (4) and (b)(7)(i) and (ii) of this section. This requirement includes periods of startup, shutdown, and malfunction.

(i) The total operating time of each affected source during the reporting period.

(ii) Information on the number, duration, and cause of deviations (including unknown cause) as applicable and the corrective action taken.

(8) For each deviation from an emissions limitation (including an operating limit) or work practice standard occurring at an affected source where you are using a continuous monitoring system (including a CPMS or CEMS) to comply with the emissions limitations or work practice standard in this subpart, you must include the information specified in paragraphs (b)(1) through (4) and (b)(8)(i) through (xi) of this section. This requirement includes periods of startup, shutdown, and malfunction.

(i) The date and time that each malfunction started and stopped.

(ii) The date and time that each continuous monitoring system was inoperative, except for zero (low-level) and high-level checks.

(iii) The date, time, and duration that each continuous monitoring system was out-of-control, including the information in §63.8(c)(8).

(iv) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(v) A summary of the total duration of the deviations during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(vi) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and unknown causes.

(vii) A summary of the total duration of continuous monitoring system downtime during the reporting period and the total duration of continuous monitoring system downtime as a percent of the total source operating time during the reporting period.

(viii) A brief description of the process units.

(ix) A brief description of the continuous monitoring system.

(x) The date of the latest continuous monitoring system certification or audit.

(xi) A description of any changes in continuous monitoring systems, processes, or controls since the last reporting period.

(9) You must include the information on equipment leaks required in periodic reports by §63.1018(a) or §63.1039(b).

(c) Immediate startup, shutdown, and malfunction report. If you had a startup, shutdown, or malfunction during the semiannual reporting period that was not consistent with your startup, shutdown, and malfunction plan, you must submit an immediate startup, shutdown, and malfunction report according to the requirements of §63.10(d)(5)(ii) .

(d) Part 70 monitoring report. If you have obtained a title V operating permit for an affected source pursuant to 40 CFR part 70 or 40 CFR part 71, you must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If you submit a compliance report for an affected source along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all the required information concerning deviations from any emissions limitation or operation and maintenance requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation you may have to report deviations from permit requirements for an affected source to your permitting authority.

§ 63.7952 What records must I keep?

(a) You must keep the records specified in paragraphs (a)(1) through (4) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirements in §63.10(b)(1) and (b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startups, shutdowns, and malfunctions.

(3) Results of performance tests and performance evaluations as required by §63.10(b)(2)(viii).

(4) The records of initial and ongoing determinations for affected sources that are exempt from control requirements under this subpart.

(b) For each continuous monitoring system, you must keep the records as described in paragraphs (b)(1) and (2) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi) that apply to your continuous monitoring system.

(2) Performance evaluation plans, including previous (i.e., superseded) versions of the plan as required in §63.8(d)(3).

(c) You must keep the records required by this subpart to show continuous compliance with each emissions limitation, work practice standard, and operation and maintenance requirement that applies to you.

(d) You must record, on a semiannual basis, the information in §63.696(g) for planned routine maintenance of a control device for emissions from process vents.

§ 63.7953 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep your files of all information (including all reports and notifications) for 5 years following the date of each occurrence, measurement, maintenance, action taken to correct the cause of a deviation, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off-site for the remaining 3 years.

(d) If, after the remediation activity is completed, there is no other remediation activity at the facility, and you are no longer the owner of the facility, you may keep all records for the completed remediation activity at an off-site location provided you notify the Administrator in writing of the name, address and contact person for the off-site location.

Other Requirements and Information

§ 63.7955 What parts of the General Provisions apply to me?

Table 3 of this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§ 63.7956 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by us, the EPA, or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency, in addition to the EPA, has the authority to implement and enforce this subpart. You should contact your EPA Regional Office (see list in §63.13) to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under section 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that cannot be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the non-opacity emissions limitations and work practice standards in this subpart under §63.6(g).

(2) Approval of major changes to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major changes to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major changes to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69019, Nov. 29, 2006]

§ 63.7957 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in §63.2, and in this section. If a term is defined both in this section and in another subpart cross-referenced by this subpart, then the term will have the meaning given in this section for purposes of this subpart.

***Boiler* means an enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator or a process heater.**

***Closed vent system* means a system that is not open to the atmosphere and is composed of hard-piping, ductwork, connections, and, if necessary, fans, blowers, or other flow-inducing device that conveys gas or vapor from an emissions point to a control device.**

***Closure device* means a cap, hatch, lid, plug, seal, valve, or other type of fitting that prevents or reduces air pollutant emissions to the atmosphere by blocking an opening in a cover when the device is secured in the closed position. Closure devices include devices that are detachable from the cover (*e.g.,* a sampling port cap), manually operated (*e.g.,* a hinged access lid or hatch), or automatically operated (*e.g.,* a spring-loaded pressure relief valve).**

***Container* means a portable unit used to hold material. Examples of containers include, but are not limited to drums, dumpsters, roll-off boxes, bulk cargo containers commonly known as portable tanks or totes, cargo tank trucks, dump trucks, and rail cars. For the purpose of this subpart, a front-end loader, excavator, backhoe, or other type of self-propelled excavation equipment is not a container.**

***Continuous record* means documentation of data values measured at least once every 15 minutes and recorded at the frequency specified in this subpart.**

***Continuous recorder* means a data recording device that either records an instantaneous data value at least once every 15 minutes or records 15-minutes or more frequent block averages.**

***Control device* means equipment used recovering, removing, oxidizing, or destroying organic vapors. Examples of such equipment include but are not limited to carbon adsorbers, condensers, vapor incinerators, flares, boilers, and process heaters.**

Cover **means a device that prevents or reduces air pollutant emissions to the atmosphere by forming a continuous barrier over the remediation material managed in a unit. A cover may have openings (such as access hatches, sampling ports, gauge wells) that are necessary for operation, inspection, maintenance, and repair of the unit on which the cover is used. A cover may be a separate piece of equipment which can be detached and removed from the unit (such as a tarp) or a cover may be formed by structural features permanently integrated into the design of the unit.**

Deviation **means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:**

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emissions limitation (including any operating limit), or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emissions limitation, (including any operating limit), or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Emissions limitation **means any emissions limit, opacity limit, operating limit, or visible emissions limit.**

Emissions point **means an individual tank, surface impoundment, container, oil-water, organic-water separator, transfer system, vent, or enclosure.**

Enclosure **means a structure that surrounds a tank or container, captures organic vapors emitted from the tank or container, and vents the captured vapor through a closed vent system to a control device.**

Equipment **means each pump, pressure relief device, sampling connection system, valve, and connector used in remediation material service at a facility.**

External floating roof **means a pontoon-type or double-deck type cover that rests on the liquid surface in a tank with no fixed roof.**

Facility **means all contiguous or adjoining property that is under common control including properties that are separated only by a road or other public right-of-way. Common control includes properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination thereof. A unit or group of units within a contiguous property that are not under common control (** ***e.g.,*** **a wastewater treatment unit located at the facility but is owned by a different company) is a different facility.**

Fixed roof **means a cover that is mounted on a unit in a stationary position and does not move with fluctuations in the level of the liquid managed in the unit.**

Flame zone **means the portion of the combustion chamber in a boiler or process heater occupied by the flame envelope.**

Floating roof **means a cover consisting of a double deck, pontoon single deck, or internal floating cover which rests upon and is supported by the liquid being contained, and is equipped with a continuous seal.**

Flow indicator **means a device that indicates whether gas is flowing, or whether the valve position would allow gas to flow in a bypass line.**

Hard-piping **means pipe or tubing that is manufactured and properly installed according to relevant standards and good engineering practices.**

Individual drain system **means a stationary system used to convey wastewater streams or residuals to a remediation material management unit or to discharge or disposal. The term includes hard-piping, all drains and junction boxes, together with their associated sewer lines and other junction boxes (*e.g.,* manholes, sumps, and lift stations) conveying wastewater streams or residuals. For the purpose of this subpart, an individual drain system is not a drain and collection system that is designed and operated for the sole purpose of collecting rainfall runoff (*e.g.,* stormwater sewer system) and is segregated from all other individual drain systems.**

Internal floating roof **means a cover that rests or floats on the liquid surface (but not necessarily in complete contact with it inside a tank that has a fixed roof).**

Maximum HAP vapor pressure **means the sum of the individual HAP equilibrium partial pressure exerted by remediation material at the temperature equal to either: the monthly average temperature as reported by the National Weather Service when the remediation material is stored or treated at ambient temperature; or the highest calendar-month average temperature of the remediation material when the remediation material is stored at temperatures above the ambient temperature or when the remediation material is stored or treated at temperatures below the ambient temperature. For the purpose of this subpart, maximum HAP vapor pressure is determined using the procedures specified in §63.7944.**

No detectable organic emissions **means no escape of organics to the atmosphere as determined using the procedure specified in §63.694(k).**

Oil-water separator **means a separator as defined for this subpart that is used to separate oil from water.**

Operating parameter value **means a minimum or maximum value established for a control device or treatment process parameter which, if achieved by itself or in combination with one or more other operating parameter values, determines that an owner or operator has complied with an applicable emissions limitation or standard.**

Organic-water separator **means a separator as defined for this subpart that is used to separate organics from water.**

Process heater **means an enclosed combustion device that transfers heat released by burning fuel directly to process streams or to heat transfer liquids other than water.**

Process vent **means any open-ended pipe, stack, duct, or other opening intended to allow the passage of gases, vapors, or fumes to the atmosphere and this passage is caused by mechanical means (such as compressors, vacuum-producing systems or fans) or by process-related means (such as volatilization produced by heating). For the purposes of this subpart, a process vent is neither a safety device (as defined in this section) nor a stack, duct or other opening used to exhaust combustion products from a boiler, furnace, heater, incinerator, or other combustion device.**

Radioactive mixed waste **means a material that contains both hazardous waste subject to RCRA and source, special nuclear, or by-product material subject to the Atomic Energy Act of 1954.**

Remediation material **means a material that contains one or more of the HAP listed in Table 1 of this subpart, and this material is one of the following:**

(1) A material found in naturally occurring media such as soil, groundwater, surface water, sediments, or a mixture of such materials with liquids, sludges, or solids which is inseparable by simple mechanical removal processes and is made up primarily of media. This material does not include debris as defined in 40 CFR 268.2.

(2) A material found in intact or substantially intact containers, tanks, storage piles, or other storage units that requires clean up because this material poses a reasonable potential threat to contaminating media. Examples of these materials include, but are not limited to, solvents, oils, paints, and other volatile or semi-volatile organic liquids found in buried drums, cans, or other containers; gasoline, fuel oil, or other fuels in leaking underground storage tanks; and solid materials containing volatile or semi-volatile organics in unused or abandoned piles. Remediation material is not a waste or residue generated by routine equipment maintenance activities performed at a facility such as, but not limited to, tank bottoms and sludges removed during tank cleanouts; sludges and sediments removed from active wastewater treatment tanks, surface impoundments, or lagoons; spent catalyst removed from process equipment; residues removed from air pollution control equipment; and debris removed during heat exchanger and pipeline cleanouts.

Remediation material management **unit means a tank, container, surface impoundment, oil-water separator, organic-water separator, or transfer system used to remove, destroy, degrade, transform, immobilize, or otherwise manage remediation material.**

Remediation material service **means any time when a pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, or instrumentation system contains or contacts remediation material.**

Responsible official **means responsible official as defined in 40 CFR 70.2.**

Safety device **means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions to prevent physical damage or permanent deformation to equipment by venting gases or vapors during unsafe conditions resulting from an unplanned, accidental, or emergency event. For the purpose of this Subpart, a safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in this vapor headspace in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes, standard engineering codes and practices, or other requirements for the safe handling of flammable, combustible, explosive, reactive, or hazardous materials.**

Separator **means a remediation material management unit, generally a tank, used to separate oil or organics from water. A separator consists of not only the separation unit but also the forebay and other separator basins, skimmers, weirs, grit chambers, sludge hoppers, and bar screens that are located directly after the individual drain system and prior to any additional treatment units such as an air flotation unit clarifier or biological treatment unit. Examples of a separator include, but are not limited to, an API separator, parallel-plate interceptor, and corrugated-plate interceptor with the associated ancillary equipment.**

Site remediation **means one or more activities or processes used to remove, destroy, degrade, transform, immobilize, or otherwise manage remediation material. The monitoring or measuring of contamination levels in environmental media using wells or by sampling is not considered to be a site remediation.**

Sludge **means sludge as defined in §260.10 of this chapter.**

Soil **means unconsolidated earth material composing the superficial geologic strata (material overlying bedrock), consisting of clay, silt, sand, or gravel size particles (sizes as classified by the U.S. Soil Conservation Service), or a mixture of such materials with liquids, sludges, or solids which is inseparable by simple mechanical removal processes and is made up primarily of soil.**

Stabilization process **means any physical or chemical process used to either reduce the mobility of contaminants in media or eliminate free liquids as determined by Test Method 9095—Paint Filter Liquids Test in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW–846, Third Edition, September 1986, as amended by Update I, November 15, 1992. (As an alternative, you may use any more recent, updated version of Method 9095 approved by the EPA). A stabilization process includes mixing remediation material with binders or other materials, and curing the resulting remediation material and binder mixture. Other synonymous terms used to refer to this process are fixation or solidification. A stabilization process does not include the adding of absorbent materials to the surface of remediation material, without mixing, agitation, or subsequent curing, to absorb free liquid.**

Surface impoundment **means a unit that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to hold an accumulation of liquids. Examples of surface impoundments include holding, storage, settling, and aeration pits, ponds, and lagoons.**

Tank **means a stationary unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support and is designed to hold an accumulation of liquids or other materials.**

Temperature monitoring device **means a piece of equipment used to monitor temperature and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius (°C) or ±1.2 degrees °C, whichever value is greater.**

Transfer system **means a stationary system for which the predominant function is to convey liquids or solid materials from one point to another point within a waste management operation or recovery operation. For the purpose of this subpart, the conveyance of material using a container (as defined for this subpart) or a self-propelled vehicle (*e.g.* , a front-end loader) is not a transfer system. Examples of a transfer system include but are not limited to a pipeline, an individual drain system, a gravity-operated conveyor (such as a chute), and a mechanically-powered conveyor (such as a belt or screw conveyor).**

Treatment process **means a process in which remediation material is physically, chemically, thermally, or biologically treated to destroy, degrade, or remove hazardous air pollutants contained in the material. A treatment process can be composed of a single unit (*e.g.,* a steam stripper) or a series of units (*e.g.,* a wastewater treatment system). A treatment process can be used to treat one or more remediation material streams at the same time.**

Volatile organic hazardous air pollutant (VOHAP) concentration **means the fraction by weight of the HAP listed in Table 1 of this subpart that are contained in the remediation material as measured using Method 305, 40 CFR part 63, appendix A and expressed in terms of parts per million (ppm). As an alternative to using Method 305, 40 CFR part 63, appendix A, you may determine the HAP concentration of the remediation material using any one of the other test methods specified in §63.694(b)(2)(ii). When a test method specified in §63.694(b)(2)(ii) other than Method 305 in 40 CFR part 63, appendix A is used to determine the speciated HAP concentration of the contaminated material, the individual compound concentration may be adjusted by the corresponding f_{m305}listed in Table 1 of this subpart to determine a VOHAP concentration.**

Work practice standard **means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.**

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 69019, Nov. 29, 2006]

Table 1 to Subpart GGGGG of Part 63.—List of Hazardous Air Pollutants

CAS No.[a]	Compound name	F_{m305}
75070	Acetaldehyde	1.000
75058	Acetonitrile	0.989

98862	Acetophenone	0.314
98862	Acetophenone	0.314
107028	Acrolein	1.000
107131	Acrylonitrile	0.999
107051	Allyl chloride	1.000
71432	Benzene (includes benzene in gasoline)	1.000
98077	Benzotrichloride (isomers and mixture)	0.958
100447	Benzyl chloride	1.000
92524	Biphenyl	0.864
542881	Bis(chloromethyl)ether[b]	0.999
75252	Bromoform	0.998
106990	1,3-Butadiene	1.000
75150	Carbon disulfide	1.000
56235	Carbon Tetrachloride	1.000
43581	Carbonyl sulfide	1.000
133904	Chloramben	0.633
108907	Chlorobenzene	1.000
67663	Chloroform	1.000
107302	Chloromethyl methyl ether[b]	1.000
126998	Chloroprene	1.000
98828	Cumene	1.000
94757	2,4-D, salts and esters	0.167
334883	Diazomethane[c]	0.999
132649	Dibenzofurans	0.967
96128	B1,2-Dibromo-3-chloropropane	1.000
106467	1,4-Dichlorobenzene(p)	1.000
107062	Dichloroethane (Ethylene dichloride)	1.000
111444	Dichloroethyl ether (Bis(2-chloroethylether)	0.757
542756	1,3-Dichloropropene	1.000
64675	Diethyl sulfate	0.0025
79447	Dimethyl carbamoyl chloride[c]	0.150
77781	Dimethyl sulfate	0.086
121697	N,N-Dimethylaniline	0.0008

51285	**2,4-Dinitrophenol**	**0.0077**
121142	**2,4-Dinitrotoluene**	**0.0848**
123911	**1,4-Dioxane (1,4-Diethyleneoxide)**	**0.869**
106898	**Epichlorohydrin (1-Chloro-2,3-epoxypropane)**	**0.939**
106887	**1,2-Epoxybutane**	**1.000**
140885	**Ethyl acrylate**	**1.000**
100414	**Ethyl benzene**	**1.000**
75003	**Ethyl chloride (Chloroethane)**	**1.000**
106934	**Ethylene dibromide (Dibromoethane)**	**0.999**
107062	**Ethylene dichloride (1,2-Dichloroethane)**	**1.000**
151564	**Ethylene imine (Aziridine)**	**0.867**
75218	**Ethylene oxide**	**1.000**
75343	**Ethylidene dichloride (1,1-Dichloroethane)** **Glycol ethers[d] that have a Henry's Law Constant value equal to or greater than 0.01 Y/X(1.8 × 10^{-6} atm/gm-mole/m^3) at 25 °C**	**1.000 [[e]]**
118741	**Hexachlorobenzene**	**0.97**
87683	**Hexachlorobutadiene**	**0.88**
67721	**Hexachloroethane**	**0.499**
110543	**Hexane**	**1.000**
78591	**Isophorone**	**0.506**
58899	**Lindane (all isomers)**	**1.000**
67561	**Methanol**	**0.855**
74839	**Methyl bromide (Bromomethane)**	**1.000**
74873	**Methyl chloride (Choromethane)**	**1.000**
71556	**Methyl chloroform (1,1,1-Trichloroethane)**	**1.000**
74884	**Methyl iodide (Iodomethane)**	**1.000**
108101	**Methyl isobutyl ketone (Hexone)**	**0.979**
624839	**Methyl isocyanate**	**1.000**
80626	**Methyl methacrylate**	**0.999**
1634044	**Methyl tert butyl ether**	**1.000**
75092	**Methylene chloride (Dichloromethane)**	**1.000**
91203	**Naphthalene**	**0.994**
98953	**Nitrobenzene**	**0.394**
79469	**2-Nitropropane**	**0.989**

82688	Pentachloronitrobenzene (Quintobenzene)	0.839
87865	Pentachlorophenol	0.0898
75445	Phosgene[c]	1.000
123386	Propionaldehyde	0.999
78875	Propylene dichloride (1,2-Dichloropropane)	1.000
75569	Propylene oxide	1.000
75558	1,2-Propylenimine (2-Methyl aziridine)	0.945
100425	Styrene	1.000
96093	Styrene oxide	0.830
79345	1,1,2,2-Tetrachloroethane	0.999
127184	Tetrachloroethylene (Perchloroethylene)	1.000
108883	Toluene	1.000
95534	o-Toluidine	0.152
120821	1,2,4-Trichlorobenzene	1.000
71556	1,1,1-Trichloroethane (Methyl chlorform)	1.000
79005	1,1,2-Trichloroethane (Vinyltrichloride)	1.000
79016	Trichloroethylene	1.000
95954	2,4,5-Trichlorophenol	0.0108
88062	2,4,6-Trichlorophenol	0.0132
121448	Triethylamine	1.000
540841	2,2,4-Trimethylpentane	1.000
108054	Vinyl acetate	1.000
593602	Vinyl bromide	1.000
75014	Vinyl chloride	1.000
75354	Vinylidene chloride (1,1-Dichloroethylene)	1.000
1330207	Xylenes (isomers and mixture)	1.000
95476	o-Xylenes	1.000
108383	m-Xylenes	1.000
106423	p-Xylenes	1.000

Notes:

F_{m305}Fraction measure factor in Method 305, 40 CFR 305 part 63, appendix A.

[a]CAS numbers refer to the Chemical Abstracts Services registry number assigned to specific compounds, isomers, or mixtures of compounds.

[b]Denotes a HAP that hydrolyzes quickly in water, but the hydrolysis products are also HAP chemicals.

[c]Denotes a HAP that may react violently with water.

[d]Denotes a HAP that hydrolyzes slowly in water.

[e]The F_{m305}factors for some of the more common glycol 305 ethers can be obtained by contacting the Waste and Chemical Processes Group, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

[71 FR 69020, Nov. 29, 2006]

Table 2 to Subpart GGGGG of Part 63—Control Levels as Required by §63.7895(a) for Tanks Managing Remediation Material With a Maximum HAP Vapor Pressure Less Than 76.6kPa

If your tank design capacity is . . .	And the maximum HAP vapor pressure of the remediation material placed in your tank is . . .	Then your tank must use . . .
1. Less than 38 m^3	Less than 76.6 kPa	Tank Level 1 controls under §63.7895(b).
2. At least 38 m^3but less than 151 m^3	Less than 13.1 kPa	Tank Level 1 controls under §63.7895(b).
3. 151 m^3or greater	Less than 0.7 kPa	Tank Level 1 controls under §63.7895(b).
4. at least 38 m^3but less than 151 m^3	13.1 kPa or greater	Tank Level 2 controls under §63.7895(c).
5. 151 m^3or greater	0.7 kPa or greater	Tank Level 2 controls under §63.7895(c)

Table 3 to Subpart GGGGG of Part 63—Applicability of General Provisions to Subpart GGGGG

As stated in §63.7940, you must comply with the applicable General Provisions requirements according to the following table:

Citation	Subject	Brief description	Applies to subpart GGGGG
§63.1	Applicability	Initial Applicability Determination; Applicability After Standard Established; Permit Requirements; Extensions, Notifications	Yes.
§63.2	Definitions	Definitions for part 63 standards	Yes.
§63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.
§63.4	Prohibited Activities	Prohibited Activities; Compliance date; Circumvention, Severability	Yes.
§63.5	Construction/Reconstruction	Applicability; applications; approvals	Yes.
§63.6(a)	Applicability	General Provisions (GP) apply unless compliance extension GP apply to area sources that become major	Yes.
§63.6(b)(1)–(4)	Compliance Dates for New and Reconstructed sources	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for 112(f)	Yes.
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.

§63.6(b)(6)	**[Reserved]**		
§63.6(b)(7)	**Compliance Dates for New and Reconstructed Area Sources That Become Major**	**Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source**	**Yes.**
§63.6(c)(1)–(2)	**Compliance Dates for Existing Sources**	**Comply according to date in subpart, which must be no later than 3 years after effective date. For 112(f) standards, comply within 90 days of effective date unless compliance extension**	**Yes.**
§63.6(c)(3)–(4)	**[Reserved]**		
§63.6(c)(5)	**Compliance Dates for Existing Area Sources That Become Major**	**Area sources that become major must comply with major source standards by date indicated in subpart or by equivalent time period (for example, 3 years)**	**Yes.**
§63.6(d)	**[Reserved]**		
§63.6(e)(1)–(2)	**Operation & Maintenance**	**Operate to minimize emissions at all times. Correct malfunctions as soon as practicable. Operation and maintenance requirements independently enforceable; information Administrator will use to determine if operation and maintenance requirements were met**	**Yes.**
§63.6(e)(3)	**Startup, Shutdown, and Malfunction Plan (SSMP)**	**Requirement for startup, shutdown and malfunction (SSM) and SSMP. Content of SSMP**	**Yes with the exception of containers using either Level 1 or Level 2 controls.**
§63.6(f)(1)	**Compliance Except During SSM**	**You must comply with emissions standards at all times except during SSM**	**Yes.**
§63.6(f)(2)–(3)	**Methods for Determining Compliance**	**Compliance based on performance test, operation and maintenance plans, records, inspection**	**Yes.**
§63.6(g)(1)–(3)	**Alternative Standard**	**Procedures for getting an alternative standard**	**Yes.**
§63.6(h)	**Opacity/Visible Emissions (VE) Standards**	**Requirements for opacity and visible emissions limits**	**No. No opacity standards.**
§63.6(i)(1)–(14)	**Compliance Extension**	**Procedures and criteria for Administrator to grant compliance extension**	**Yes.**
§63.6(j)	**Presidential Compliance**	**President may exempt source category**	**Yes.**

	Exemption	**from requirement to comply with final rule**	
§63.7(a)(1)–(2)	**Performance Test Dates**	**Dates for Conducting Initial Performance Testing and Other Compliance Demonstrations. Must conduct 180 days after first subject to final rule**	**Yes.**
§63.7(a)(3)	**CAA Section 114 Authority**	**Administrator may require a performance test under CAA section 114 at any time**	**Yes.**
§63.7(b)(1)	**Notification of Performance Test**	**Must notify Administrator 60 days before the test**	**Yes.**
§63.7(b)(2)	**Notification of Rescheduling**	**If rescheduling a performance test is necessary, must notify Administrator 5 days before scheduled date of rescheduled date**	**Yes.**
§63.7(c)	**Quality Assurance/Test Plan**	**Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with: Test plan approval procedures; performance audit requirements; internal and external QA procedures for testing**	**Yes.**
§63.7(d)	**Testing Facilities**	**Requirements for testing facilities**	**Yes.**
§63.7(e)(1)	**Conditions for Conducting Performance Tests**	**Performance tests must be conducted under representative conditions. Cannot conduct performance tests during SSM. Not a violation to exceed standard during SSM**	**Yes.**
§63.7(e)(2)	**Conditions for Conducting Performance Tests**	**Must conduct according to rule and EPA test methods unless Administrator approves alternative**	**Yes.**
§63.7(e)(3)	**Test Run Duration**	**Must have three test runs of at least one hour each. Compliance is based on arithmetic mean of three runs. Conditions when data from an additional test run can be used**	**Yes.**
§63.7(f)	**Alternative Test Method**	**Procedures by which Administrator can grant approval to use an alternative test method**	**Yes.**
§63.7(g)	**Performance Test Data Analysis**	**Must include raw data in performance test report. Must submit performance test data 60 days after end of test with the Notification of Compliance Status. Keep data for 5 years**	**Yes.**
§63.7(h)	**Waiver of Tests**	**Procedures for Administrator to waive performance test**	**Yes.**

§63.8(a)(1)	**Applicability of Monitoring Requirements**	**Subject to all monitoring requirements in standard**	**Yes.**
§63.8(a)(2)	**Performance Specifications**	**Performance Specifications in appendix B of part 60 apply**	**Yes.**
§63.8(a)(3)	**[Reserved]**		
§63.8(a)(4)	**Monitoring with Flares**	**Unless your rule says otherwise, the requirements for flares in 63.11 apply**	**Yes.**
§63.8(b)(1)	**Monitoring**	**Must conduct monitoring according to standard unless Administrator approves alternative**	**Yes.**
§63.8(b)(2)–(3)	**Multiple Effluents and Multiple Monitoring Systems**	**Specific requirements for installing monitoring systems. Must install on each effluent before it is combined and before it is released to the atmosphere unless Administrator approves otherwise. If more than one monitoring system on an emissions point, must report all monitoring system results, unless one monitoring system is a backup**	**Yes.**
§63.8(c)(1)	**Monitoring System Operation and Maintenance**	**Maintain monitoring system in a manner consistent with good air pollution control practices**	**Yes.**
§63.8(c)(1)(i)	**Routine and Predictable SSM**	**Keep parts for routine repairs available; reporting requirements for SSM when action is described in SSM plan**	**Yes.**
§63.8(c)(1)(ii)	**SSM not in SSMP**	**Reporting requirements for SSM when action is not described in SSM plan**	**Yes.**
§63.8(c)(1)(iii)	**Compliance with Operation and Maintenance (O&M) Requirements**	**How Administrator determines if source complying with operation and maintenance requirements. Review of source O&M procedures, records, Manufacturer's instructions, recommendations, and inspection of monitoring system**	**Yes.**
§63.8(c)(2)–(3)	**Monitoring System Installation**	**Must install to get representative emissions and parameter measurements. Must verify operational status before or at performance test**	**Yes.**
§63.8(c)(4)	**Continuous Monitoring System (CMS) Requirements**	**CMS must be operating except during breakdown, out-of-control, repair, maintenance, and high-level calibration drifts**	**No.**
§63.8(c)(4)(i)–(ii)	**Continuous Monitoring System (CMS) Requirements**	**COMS must have a minimum of one cycle of sampling and analysis for each successive 10-second period and**	**Yes. However, COMS are not applicable.**

		one cycle of data recording for each successive 6-minute period. CEMS must have a minimum of one cycle of operation for each successive 15-minute period	Requirements for CPMS are listed in §§63.7900 and 63.7913.
§63.8(c)(5)	COMS Minimum Procedures	COMS minimum procedures	No.
§63.8(c)(6)	CMS Requirements	Zero and High level calibration check requirements	Yes. However requirements for CPMS are addressed in §63.7927.
§63.8(c)(7)–(8)	CMS Requirements	Out-of-control periods, including reporting	Yes.
§63.8(d)	CMS Quality Control	Requirements for CMS quality control, including calibration, etc. Must keep quality control plan on record for 5 years. Keep old versions for 5 years after revisions	Yes.
§63.8(e)	CMS Performance Evaluation	Notification, performance evaluation test plan, reports	Yes.
§63.8(f)(1)–(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring	Yes.
§63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for CEMS	No.
§63.8(g)(1)–(4)	Data Reduction	COMS 6-minute averages calculated over at least 36 evenly spaced data points. CEMS 1-hour averages computed over at least four equally spaced data points	Yes. However, COMS are not applicable. Requirements for CPMS are addressed in §§63.7900 and 63.7913.
§63.8(g)(5)	Data Reduction	Data that cannot be used in computing averages for CEMS and COMS	No.
§63.9(a)	Notification Requirements	Applicability and State Delegation	Yes.
§63.9(b)(1)–(5)	Initial Notifications.	Submit notification 120 days after effective date. Notification of intent to construct/reconstruct; Notification of commencement of construct/reconstruct; Notification of startup. Contents of each	Yes.
§63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed BACT/LAER	Yes.
§63.9(d)	Notification of Special	For sources that commence	Yes.

	Compliance Requirements for New Source	**construction between proposal and promulgation and want to comply 3 years after effective date**	
§63.9(e)	**Notification of Performance Test**	**Notify Administrator 60 days prior**	**Yes.**
§63.9(f)	**Notification of VE/Opacity Test**	**Notify Administrator 30 days prior**	**No.**
§63.9(g)	**Additional Notifications When Using CMS**	**Notification of performance evaluation. Notification using COMS data. Notification that exceeded criterion for relative accuracy**	**Yes. However, there are no opacity standards.**
§63.9(h)(1)–(6)	**Notification of Compliance Status**	**Contents. Due 60 days after end of performance test or other compliance demonstration, except for opacity/VE, which are due 30 days after. When to submit to Federal vs. State authority**	**Yes.**
§63.9(i)	**Adjustment of Submittal Deadlines**	**Procedures for Administrator to approve change in when notifications must be submitted**	**Yes.**
§63.9(j)	**Change in Previous Information**	**Must submit within 15 days after the change**	**Yes.**
§63.10(a)	**Recordkeeping/Reporting**	**Applies to all, unless compliance extension. When to submit to Federal vs. State authority. Procedures for owners of more than 1 source**	**Yes.**
§63.10(b)(1)	**Recordkeeping/Reporting**	**General Requirements. Keep all records readily available. Keep for 5 years**	**Yes.**
§63.10(b)(2)(i)–(iv)	**Records related to SSM**	**Occurrence of each of operation (process equipment). Occurrence of each malfunction of air pollution equipment. Maintenance on air pollution control equipment. Actions during startup, shutdown, and malfunction**	**Yes.**
§63.10(b)(2)(vi) and (x–xi)	**CMS Records**	**Malfunctions, inoperative, out-of-control. Calibration checks. Adjustments, maintenance**	**Yes.**
§63.10(b)(2)(vii)–(ix)	**Records**	**Measurements to demonstrate compliance with emissions limitations. Performance test, performance evaluation, and visible emissions observation results. Measurements to determine conditions of performance tests and performance evaluations**	**Yes.**
§63.10(b)(2)(xii)	**Records**	**Records when under waiver**	**Yes.**
§63.10(b)(2)(xiii)	**Records**	**Records when using alternative to**	**No.**

		relative accuracy test	
§63.10(b)(2)(xiv)	**Records**	**All documentation supporting Initial Notification and Notification of Compliance Status**	**Yes.**
§63.10(b)(3)	**Records**	**Applicability Determinations**	**Yes.**
§63.10(c)	**Records**	**Additional Records for CMS**	**No.**
§63.10(d)(1)	**General Reporting Requirements**	**Requirement to report**	**Yes.**
§63.10(d)(2)	**Report of Performance Test Results**	**When to submit to Federal or State authority**	**Yes.**
§63.10(d)(3)	**Reporting Opacity or VE Observations**	**What to report and when**	**No.**
§63.10(d)(4)	**Progress Reports**	**Must submit progress reports on schedule if under compliance extension**	**Yes.**
§63.10(d)(5)	**Startup, Shutdown, and Malfunction Reports**	**Contents and submission**	**Yes.**
§63.10(e)(1)–(2)	**Additional CMS Reports**	**Must report results for each CEM on a unit Written copy of performance evaluation Three copies of COMS performance evaluation**	**Yes. However, COMS are not applicable.**
§63.10(e)(3)	**Reports**	**Excess Emissions Reports**	**No.**
§63.10(e)(3)(i–iii)	**Reports**	**Schedule for reporting excess emissions and parameter monitor exceedance (now defined as deviations)**	**No.**
§63.10(e)(3)(iv–v)	**Excess Emissions Reports**	**Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedance (now defined as deviations). Provision to request semiannual reporting after compliance for one year. Submit report by 30th day following end of quarter or calendar half. If there has not been an exceedance or excess emissions (now defined as deviations), report contents is a statement that there have been no deviations**	**No.**
§63.10(e)(3)(iv–v)	**Excess Emissions Reports**	**Must submit report containing all of the information in §§63.10(c)(5–13) and 63.8(c)(7–8)**	**No.**
§63.10(e)(3)(vi–viii)	**Excess Emissions Report and Summary Report**	**Requirements for reporting excess emissions for CMSs (now called deviations). Requires all of the information in §§63.10(c)(5–13) and**	**No.**

		63.8(c)(7–8)	
§63.10(e)(4)	**Reporting COMS data**	**Must submit COMS data with performance test data**	**No.**
§63.10(f)	**Waiver for Recordkeeping/Reporting**	**Procedures for Administrator to waive**	**Yes.**
§63.11	**Flares**	**Requirements for flares**	**Yes.**
§63.12	**Delegation**	**State authority to enforce standards**	**Yes.**
§63.13	**Addresses**	**Addresses where reports, notifications, and requests are sent**	**Yes.**
§63.14	**Incorporation by Reference**	**Test methods incorporated by reference**	**Yes.**
§63.15	**Availability of Information**	**Public and confidential information**	**Yes**

[68 FR 58190, Oct. 8, 2003, as amended at 71 FR 20468, Apr. 20, 2006]

Section E.22 40 CFR 60, Subpart Db—New Source Performance Standards - Industrial-Commercial-Institutional Steam Generating Units

E.22.1 NSPS Subpart Db Requirements [40 CFR Part 60, Subpart Db] [326 IAC 12]

Pursuant to 40 CFR 60.40b, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart Db for New Boiler 1 and New Boiler 2 as specified below:

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NOX) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are subject to the PM and NOx standards under this subpart and to the sulfur dioxide (SO2) standards under subpart D (§60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NOXstandards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are also subject to the NOXstandards under this subpart and the PM and SO2standards under subpart D (§60.42 and §60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the PM and NOXstandards under this subpart and the SO2standards under subpart J (§60.104).

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; §60.50) are subject to the NOXand PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).
(2) Section 60.44b(g).
(3) Section 60.49b(a)(4).

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, or subpart AAAA of this part is not covered by this subpart.

(i) Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart GG or KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

(k) Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

§ 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO_2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration , also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.
Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO2control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is present as a gas at ISO conditions.

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m3 (70,000 Btu/hr-ft3).
ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m3 (70,000 Btu/hr-ft3) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical SO2emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO2emission control, has a SO2emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005, very low sulfur oil means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without SO2emission control, has a SO2emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

§ 60.42b Standard for sulfur dioxide (SO2).

(a) Except as provided in paragraphs (b), (c), (d), or (k) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO2in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

Where:
Es= SO2emission limit, in ng/J or lb/MMBtu heat input;
Ka= 520 ng/J (or 1.2 lb/MMBtu);
Kb= 340 ng/J (or 0.80 lb/MMBtu);
Ha= Heat input from the combustion of coal, in J (MMBtu); and
Hb= Heat input from the combustion of oil, in J (MMBtu).
Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO2in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO2emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable.

(c) On and after the date on which the performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO2emissions, shall cause to be discharged into the atmosphere any gases that contain SO2in excess of 50 percent of the potential SO2emission rate (50 percent reduction) and that contain SO2in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:
Es= SO2emission limit, in ng/J or lb/MM Btu heat input;
Kc= 260 ng/J (or 0.60 lb/MMBtu);
Kd= 170 ng/J (or 0.40 lb/MMBtu);
Hc= Heat input from the combustion of coal, in J (MMBtu); and
Hd= Heat input from the combustion of oil, in J (MMBtu).
Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO2in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or
(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and §60.45b(a), the SO2emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO2emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:
(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO2emissions and
(2) Emissions from the pretreated fuel (without combustion or post-combustion SO2control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO2control system is not being operated because of malfunction or maintenance of the SO2control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in §60.45b(c) or §60.45b(d), and following the monitoring procedures as described in §60.47b(a) or §60.47b(b) to determine SO2emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in §60.49b(r).

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO2emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

(2) Units firing only very low sulfur oil and/or a mixture of gaseous fuels with a potential SO2emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO2emissions limit in paragraph 60.42b(k)(1).

(3) Units that are located in a noncontinental area and that combust coal or oil shall not discharge any gases that contain SO2in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO2emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

§ 60.43b Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input, (i) If the affected facility combusts only coal, or
(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,
(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,
(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and
(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.
(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO2emissions is not subject to the PM limits under §60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO2emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and
(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.3 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO2or PM emissions is not subject to the PM limits under §60.43b(h)(1).

§ 60.44b Standard for nitrogen oxides (NOX).

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOX(expressed as NO2) in excess of the following emission limits:

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBTu
(1) Natural gas and distillate oil, except (4):		
(i) Low heat release rate	43	0.10
(ii) High heat release rate	86	0.20
(2) Residual oil:		

(i) Low heat release rate	**130**	**0.30**
(ii) High heat release rate	**170**	**0.40**
(3) Coal:		
(i) Mass-feed stoker	**210**	**0.50**
(ii) Spreader stoker and fluidized bed combustion	**260**	**0.60**
(iii) Pulverized coal	**300**	**0.70**
(iv) Lignite, except (v)	**260**	**0.60**
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	**340**	**0.80**
(vi) Coal-derived synthetic fuels	**210**	**0.50**
(4) Duct burner used in a combined cycle system:		
(i) Natural gas and distillate oil	**86**	**0.20**
(ii) Residual oil	**170**	**0.40**

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOXin excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:
En= NOXemission limit (expressed as NO2), ng/J (lb/MMBtu);
ELgo= Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);
Hgo= Heat input from combustion of natural gas or distillate oil, J (MMBtu);
ELro= Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);
Hro= Heat input from combustion of residual oil, J (MMBtu);
ELc= Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and
Hc= Heat input from combustion of coal, J (MMBtu).

(c) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NOXin excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOXin excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NOXin excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:
En= NOXemission limit (expressed as NO2), ng/J (lb/MMBtu);
ELgo= Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);
Hgo= Heat input from combustion of natural gas, distillate oil and gaseous byproduct/waste, J (MMBtu);
ELro= Appropriate emission limit from paragraph (a)(2) for combustion of residual oil and/or byproduct/waste, ng/J (lb/MMBtu);
Hro= Heat input from combustion of residual oil, J (MMBtu);
ELc= Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and
Hc= Heat input from combustion of coal, J (MMBtu).

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NOXemission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NOXemissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NOXemission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in §60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NOXemission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NOXemission limit will be established at the NOXemission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NOXemissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NOXlimit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NOXemission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NOXemissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NOXemission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NOXemission limits of this section. The NOXemission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NOXlimit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the NOXstandards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NOXemission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOX(expressed as NO2) in excess of the following limits:
(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: A limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or
(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:
En= NOXemission limit, (lb/MMBtu);
Hgo= 30-day heat input from combustion of natural gas or distillate oil; and
Hr= 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i) of subpart Da of this part, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO2emission standards under §60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil and complying with the fuel based limit under §60.42b(d) or §60.42b(k)(2) are allowed to exceed the limit 30 operating days per calendar year for by-product plant maintenance.

(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO2emission rate (% Ps) and the SO2emission rate (Es) pursuant to §60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO2standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A of this part are used to determine the hourly SO2emission rate (Eho) and the 30-day average emission rate (Eao). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS) of §60.47b (a) or (b).
(ii) The percent of potential SO2emission rate (%Ps) emitted to the atmosphere is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:
%Ps= Potential SO2emission rate, percent;
%Rg= SO2removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and
%Rf= SO2removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.
(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:
(i) An adjusted hourly SO2emission rate (Ehoo) is used in Equation 19–19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate (Eaoo). The Eho° is computed using the following formula:

$$E_{ho}^{\circ} = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

Where:
Ehoo = Adjusted hourly SO2emission rate, ng/J (lb/MMBtu);
Eho= Hourly SO2emission rate, ng/J (lb/MMBtu);
Ew= SO2concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value Ewfor each fuel lot is used for each hourly average during the time that the lot is being combusted; and
Xk= Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.
(ii) To compute the percent of potential SO2emission rate (%Ps), an adjusted %Rg(%Rgo) is computed from the adjusted Eaoo from paragraph (b)(3)(i) of this section and an adjusted average SO2inlet rate
(Eaio) using the following formula:

$$\%R_g^{\circ} = 100\left(1.0 - \frac{E_{ao}^{\circ}}{E_{ai}^{\circ}}\right)$$

To compute Eaio , an adjusted hourly SO2inlet rate (Ehio) is used. The Ehio is computed using the following formula:

$$E_{hi}^{\circ} = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

Where:
Ehio = Adjusted hourly SO2inlet rate, ng/J (lb/MMBtu); and
Ehi= Hourly SO2inlet rate, ng/J (lb/MMBtu).

(4) The owner or operator of an affected facility subject to paragraph (b)(3) of this section does not have to measure parameters Ewor Xkif the owner or operator elects to assume that Xk= 1.0. Owners or operators of affected facilities who assume Xk= 1.0 shall:

(i) Determine %Psfollowing the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions (Es) are considered to be in compliance with SO2emission limits under §60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of §60.42b(d) does not have to measure parameters Ewor Xkunder paragraph (b)(3) of this section if the owner or operator of the affected facility elects to measure SO2emission rates of the coal or oil following the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to §60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under §60.8, compliance with the SO2emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO2for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under §60.8, compliance with the SO2emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO2for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for SO2are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO2emissions data in calculating %Psand Ehounder paragraph (c), of this section whether or not the minimum emissions data requirements under §60.46b are achieved. All valid emissions data, including valid SO2emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating %Psand Ehopursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO2control systems when oil is combusted as provided under §60.42b(i), emission data are not used to calculate %Psor Esunder §60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under §60.42b(i).

(j) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance under §§60.42b(d)(4), 60.42b(j), and 60.42b(k)(2) shall follow the applicable procedures under §60.49b(r).

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NOXemission standards under §60.44b apply at all times.

(b) Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NOXemission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3B of appendix A of this part is used for gas analysis when applying Method 5 or 17 of appendix A of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (32 °F). The procedures of sections 2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O2) or CO2sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O2or CO2measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NOXrequired under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NOXunder §60.48(b).

(1) For the initial compliance test, NOXfrom the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NOXemission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NOXemission standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NOXemission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NOXstandards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NOXemission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NOXstandards under §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NOXemissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NOXemission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NOXemission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in §60.49b(e), the requirements of §60.48b(g)(1) apply and the provisions of §60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NOXrequired by §60.44b(a)(4) or §60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under §60.8 as follows:

(i) The emissions rate (E) of NOXshall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)\left(E_{sg} - E_g\right) \qquad \text{(Eq.1)}$$

Where:
E = Emissions rate of NOXfrom the duct burner, ng/J (lb/MMBtu) heat input;
Esg= Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;
Hg= Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);
Hb= Heat input rate to the duct burner, in J/hr (MMBtu/hr); and
Eg= Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part shall be used to determine the NOXconcentrations. Method 3A or 3B of appendix A of this part shall be used to determine O2concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under §60.44b(a)(4) or §60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under §60.48b for measuring NOXand O2and meet the requirements of §60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NOXemissions rate at the outlet from the steam generating unit shall constitute the NOXemissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method described in sections 5 and 7.3 of the ASME Power Test Codes 4.1 (incorporated by reference, see §60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of §60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of §60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NOXemission standards under §60.44b using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NOXemission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance under paragraph §60.43b(h)(5) shall follow the applicable procedures under §60.49b(r).

(j) In place of PM testing with EPA Reference Method 5, 5B, or 17 of appendix A of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 of appendix A of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(13) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.
(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O2(or CO2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraphs (j)(7)(i) of this section.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For O2(or CO2), EPA reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b), (f), and (h) of this section, the owner or operator of an affected facility subject to the SO2standards under §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO2concentrations and either O2or CO2concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO2and either O2or CO2concentrations shall both be monitored at the inlet and outlet of the SO2control device. If the owner or operator has installed and certified SO2and O2or CO2CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO2concentration data and CO2(or O2) data are collected simultaneously; and

(2) In addition to meeting the applicable SO2and CO2(or O2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of §60.49b are met. SO2and CO2(or O2) data used to meet the requirements of §60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO2data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO2emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO2input rate, or

(2) Measuring SO2according to Method 6B of appendix A of this part at the inlet or outlet to the SO2control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO2and CO2measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily SO2emission rate, ED, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A–8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19–20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO2emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average SO2emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to §60.13(h)(2). Hourly SO2emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO2CEMS at the inlet to the SO2control device is 125 percent of the maximum estimated hourly potential SO2emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO2control device is 50 percent of the maximum estimated hourly potential SO2emissions of the fuel combusted. Alternatively, SO2span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required CO2and O2monitors and for SO2and NOXmonitors with span values less than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to SO2and NOXspan values less than 100 ppm;

(ii) For all required CO2and O2monitors and for SO2and NOXmonitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO2and NOXspan values less than or equal to 30 ppm; and

(iii) For SO2, CO2, and O2monitoring systems and for NOXemission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO2(regardless of the SO2emission level during the RATA), and for NOXwhen the average NOXemission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under §60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in §60.49b(r).
§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.
(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a CEMS for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.
(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NOXstandard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NOXand O2(or CO2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NOXemission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average NOXemission rates measured by the continuous NOXmonitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a continuous monitoring system for measuring opacity shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NOXis determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NOXspan values shall be determined as follows:

Fuel	Span values for NO_X (ppm)
Natural gas	500.
Oil	500.
Coal	1,000.
Mixtures	500 (x + y) + 1,000z.

Where:
x = Fraction of total heat input derived from natural gas;
y = Fraction of total heat input derived from oil; and
z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NOXspan values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NOXemission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict NOXemission rates as specified in a plan submitted pursuant to §60.49b(c).

(h) The owner or operator of a duct burner, as described in §60.41b, that is subject to the NOXstandards of §60.44b(a)(4) or §60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NOXemissions.

(i) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a CEMS for measuring NOXemissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), or (5) of this section is not required to install or operate a COMS for measuring opacity if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO2or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under §60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO2or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in
§60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.
(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.
(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the appropriate delegated permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a CEMS, and record the output of the system, for PM emissions discharged to the atmosphere as specified in §60.46b(j). The CEMS specified in paragraph §60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4) Notification that an emerging technology will be used for controlling emissions of SO2. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO2, PM, and/or NOXemission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NOXstandard of §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under §60.48b(g)(2) and the records to be maintained under §60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NOXemission rates (i.e. , ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e. , the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e. , flue gas O2level);

(2) Include the data and information that the owner or operator used to identify the relationship between NOXemission rates and these operating conditions; and
(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(j).

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see §60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For facilities subject to the opacity standard under §60.43b, the owner or operator shall maintain records of opacity.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NOXstandards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NOXemission rates (expressed as NO2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NOXemission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NOXemission rates are in excess of the NOXemissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards under §60.43b(e) or to the operating parameter monitoring requirements under §60.13(i)(1).

(2) Any affected facility that is subject to the NOXstandard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NOXemissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NOXemission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NOXunder §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO2standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO2emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;
(3) Each 30-day average percent reduction in SO2emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO2or diluent (O2or CO2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(7) Identification of times when hourly averages have been obtained based on manual sampling methods;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO2emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which S02or diluent (O2or CO2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO2standards under §60.42(b) for which the minimum amount of data required under §60.47b(f) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (i.e. , %Rf) is used to determine the overall percent reduction (i.e. , %Ro) under §60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (i.e. , %Rf) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any NOXemission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NOXemission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) or §60.42b(k)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition and/or pipeline quality natural gas was combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For
distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NOXstandard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) Definitions .
Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.
Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) Standard for nitrogen oxides . (i) When fossil fuel alone is combusted, the NOXemission limit for fossil fuel in §60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NOXemission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) Emission monitoring . (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NOXemission limit shall be determined by the compliance and performance test methods and procedures for NOXin §60.46b(i).

(iii) The monitoring of the NOXemission limit shall be performed in accordance with §60.48b.

(4) Reporting and recordkeeping requirements . (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.
(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NOXstandard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) Definitions .
Air ratio control damper is defined as the part of the low NOXburner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.
Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) Standard for nitrogen oxides . (i) When fossil fuel alone is combusted, the NOXemission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NOXemission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) Emission monitoring for nitrogen oxides . (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NOXemission limit shall be determined by the compliance and performance test methods and procedures for NOXin §60.46b.

(iii) The monitoring of the NOXemission limit shall be performed in accordance with §60.48b.

(4) Reporting and recordkeeping requirements . (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(u) Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia . (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NOXtechnology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NOXemissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO2and/or NOXand/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NOXstandard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:
(1) Standard for nitrogen oxides . (i) When fossil fuel alone is combusted, the NOXemission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NOXemission limit is 215 ng/J (0.5 lb/MMBtu).

(2) Emission monitoring for nitrogen oxides . (i) The NOXemissions shall be determined by the compliance and performance test methods and procedures for NOXin §60.46b.

(ii) The monitoring of the NOXemissions shall be performed in accordance with §60.48b.

(3) Reporting and recordkeeping requirements . (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.
(y) Facility-specific NOXstandard for INEOS USA's AOGI located in Lima, Ohio:

(1) Standard for NOX. (i) When fossil fuel alone is combusted, the NOXemission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NOXemission limit is 645 ng/J (1.5 lb/MMBtu).

(2) Emission monitoring for NOX. (i) The NOXemissions shall be determined by the compliance and performance test methods and procedures for NOXin §60.46b.

(ii) The monitoring of the NOXemissions shall be performed in accordance with §60.48b.

(3) Reporting and recordkeeping requirements . (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

Section E.23 40 CFR 60, Subpart IIII— Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

E.23.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, except as otherwise specified in 40 CFR Part 60, Subpart IIII.

E.23.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60, Subpart IIII] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart IIII, the Permittee shall comply with the provisions of Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, which are incorporated by reference as 326 IAC 12, as specified as follows:

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are:

(i) Manufactured after April 1, 2006 and are not fire pump engines, or
(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(d) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the Federal Aid Highway System may petition the Administrator for approval to use any fuels mixed with used lubricating oil that do not meet the fuel requirements of paragraphs (a) and (b) of this section. Owners and operators must demonstrate in their petition to the Administrator that there is no other place to use the lubricating oil. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.
(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements
§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.
(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.
(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.
(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.
(3) Keeping records of engine manufacturer data indicating compliance with the standards.
(4) Keeping records of control device vendor data indicating compliance with the standards.
(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

(e) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.
(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Special Requirements

40 CFR 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

(a) Owners and operators of stationary CI ICE that do not use diesel fuel, or who have been given authority by the Administrator under §60.4207(d) of this subpart to use fuels that do not meet the fuel requirements of paragraphs (a) and (b) of §60.4207, may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4202 or §60.4203 using such fuels.

(b) [Reserved]

General Provisions

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

***Combustion turbine* means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.**

***Compression ignition* means relating to a type of stationary internal combustion engine that is not a spark ignition engine.**

***Diesel fuel* means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.**

***Diesel particulate filter* means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.**

Emergency stationary internal combustion engine **means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.**

Engine manufacturer **means the manufacturer of the engine. See the definition of "manufacturer" in this section.**

Fire pump engine **means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.**

Manufacturer **has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.**

Maximum engine power **means maximum engine power as defined in 40 CFR 1039.801.**

Model year **means either:**

(1) The calendar year in which the engine was originally produced, or

(2) The annual new model production period of the engine manufacturer if it is different than the calendar year. This must include January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year. For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was originally produced.

Other internal combustion engine **means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.**

Reciprocating internal combustion engine **means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.**

Rotary internal combustion engine **means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.**

Spark ignition **means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.**

Stationary internal combustion engine **means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.**

Subpart **means 40 CFR part 60, subpart IIII.**

Useful life **means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for useful life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for useful life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).**

Tables to Subpart IIII of Part 60

Table 1 to Subpart IIII of Part 60.—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007–2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 3 to Subpart IIII of Part 60.—Certification Requirements for Stationary Fire Pump Engines

[As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:]

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)
130≤KW≤560 (175≤HP≤750)	2009

Table 4 to Subpart IIII of Part 60.—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)

[1]For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2]For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3]In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60.—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60.—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.

[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60.—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

[As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63,	(c) Measurements to determine moisture content must be made at the same time as the measurements for

For each	Complying with the requirement to	You must	Using	According to the following requirements
			appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	NO_Xconcentration.
		iv. Measure NO_Xat the inlet and outlet of the control device	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_Xconcentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_Xin the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, Appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurement for NO_Xconcentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_Xconcentration.
		iv. Measure NO_Xat the exhaust of the stationary internal combustion engine	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_Xconcentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

For each	Complying with the requirement to	You must	Using	According to the following requirements
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, Appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.

For each	Complying with the requirement to	You must	Using	According to the following requirements
		iv. Measure PM at the exhaust of the stationary internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Table 8 to Subpart IIII of Part 60.—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Section E.24 40 CFR 63, Subpart EEEE— National Emission Standards for Hazardous Air Pollutants - Organic Liquid Distribution (Non-gasoline)

E.24.1 General Provisions Relating to NESHAP Subpart EEEE [326 IAC 20-83-1] [40 CFR Part 63, Subpart EEEE]

Pursuant to 40 CFR 63.2330 the Permittee shall comply with the provisions of 40 CFR Part 63 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, except as otherwise specified in 40 CFR Part 63, Subpart EEEE.

E.24.2 NESHAP Subpart EEEE Requirements [40 CFR 63, Subpart EEEE] [326 IAC 20-83-1]

Pursuant to 40 CFR 63.2330, the Permittee shall comply with the provisions of 40 CFR 63, Subpart EEEE, which are incorporated by refernce in 326 IAC 20-83-1, for the storage tank D-424 and other affected emissions units at this source, specified as follows:

What This Subpart Covers
§ 63.2330 What is the purpose of this subpart?

This subpart establishes national emission limitations, operating limits, and work practice standards for organic hazardous air pollutants (HAP) emitted from organic liquids distribution (OLD) (non-gasoline) operations at major sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations, operating limits, and work practice standards.

§ 63.2334 Am I subject to this subpart?

(a) Except as provided for in paragraphs (b) and (c) of this section, you are subject to this subpart if you own or operate an OLD operation that is located at, or is part of, a major source of HAP emissions. An OLD operation may occupy an entire plant site or be collocated with other industrial (*e.g.,* manufacturing) operations at the same plant site.

(b) Organic liquid distribution operations located at research and development facilities, consistent with section 112(c)(7) of the Clean Air Act (CAA), are not subject to this subpart.

(c) Organic liquid distribution operations do not include the activities and equipment, including product loading racks, used to process, store, or transfer organic liquids at facilities listed in paragraph (c) (1) and (2) of this section.

(1) Oil and natural gas production field facilities, as the term "facility" is defined in §63.761 of subpart HH.

(2) Natural gas transmission and storage facilities, as the term "facility" is defined in §63.1271 of subpart HHH.

§ 63.2338 What parts of my plant does this subpart cover?

(a) This subpart applies to each new, reconstructed, or existing OLD operation affected source.

(b) Except as provided in paragraph (c) of this section, the affected source is the collection of activities and equipment used to distribute organic liquids into, out of, or within a facility that is a major source of HAP. The affected source is composed of:

(1) All storage tanks storing organic liquids.

(2) All transfer racks at which organic liquids are loaded into or unloaded out of transport vehicles and/or containers.

(3) All equipment leak components in organic liquids service that are associated with:

(i) Storage tanks storing organic liquids;

(ii) Transfer racks loading or unloading organic liquids;

(iii) Pipelines that transfer organic liquids directly between two storage tanks that are subject to this subpart;

(iv) Pipelines that transfer organic liquids directly between a storage tank subject to this subpart and a transfer rack subject to this subpart; and

(v) Pipelines that transfer organic liquids directly between two transfer racks that are subject to this subpart.

(4) All transport vehicles while they are loading or unloading organic liquids at transfer racks subject to this subpart.

(5) All containers while they are loading or unloading organic liquids at transfer racks subject to this subpart.

(c) The equipment listed in paragraphs (c)(1) through (4) of this section and used in the identified operations is excluded from the affected source.

(1) Storage tanks, transfer racks, transport vehicles, containers, and equipment leak components that are part of an affected source under another 40 CFR part 63 national emission standards for hazardous air pollutants (NESHAP).

(2) Non-permanent storage tanks, transfer racks, transport vehicles, containers, and equipment leak components when used in special situation distribution loading and unloading operations (such as maintenance or upset liquids management).

(3) Storage tanks, transfer racks, transport vehicles, containers, and equipment leak components when used to conduct maintenance activities, such as stormwater management, liquid removal from tanks for inspections and maintenance, or changeovers to a different liquid stored in a storage tank.

(d) An affected source is a new affected source if you commenced construction of the affected source after April 2, 2002, and you meet the applicability criteria in §63.2334 at the time you commenced operation.

(e) An affected source is reconstructed if you meet the criteria for reconstruction as defined in §63.2.

(f) An affected source is existing if it is not new or reconstructed.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42904, July 28, 2006]

§ 63.2342 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to the schedule identified in paragraph (a)(1), (a)(2), or (a)(3) of this section, as applicable.

(1)(i) Except as provided in paragraph (a)(1)(ii) of this section, if you startup your new affected source on or before February 3, 2004 or if you reconstruct your affected source on or before February 3, 2004, you must comply with the emission limitations, operating limits, and work practice standards for new and reconstructed sources in this subpart no later than February 3, 2004.

(ii) For any emission source listed in paragraph §63.2338(b) at an affected source that commenced construction or reconstruction after April 2, 2002, but before February 3, 2004, that is required to be controlled based on the applicability criteria in this subpart, but:

(A) Would not have been required to be controlled based on the applicability criteria as proposed for this subpart, you must comply with the emission limitations, operating limits, and work practice standards for each such emission source based on the schedule found in paragraph (b) of this section or at startup, whichever is later; or

(B) Would have been subject to a less stringent degree of control requirement as proposed for this subpart, you must comply with the emission limitations, operating limits, and work practice standards in this subpart for each such emission source based on the schedule found in paragraph (b) of this section or at startup, whichever is later, and if you start up your affected new or reconstructed source before February 5, 2007, you must comply with the emission limitations, operating limits, and work practice standards for each such emission source as proposed for this subpart, until you are required to comply with the emission limitations, operating limits, and work practice standards in this subpart for each such emission source based on the schedule found in paragraph (b) of this section.

(2) If you commence construction of or reconstruct your affected source after February 3, 2004, you must comply with the emission limitations, operating limits, and work practice standards for new and reconstructed sources in this subpart upon startup of your affected source.

(3) If, after startup of a new affected source, the total actual annual facility-level organic liquid loading volume at that source exceeds the criteria for control in Table 2 to this subpart, items 9 and 10, the owner or operator must comply with the transfer rack requirements specified in §63.2346(b) immediately; that is, be in compliance the first day of the period following the end of the 3-year period triggering the control criteria.

(b)(1) If you have an existing affected source, you must comply with the emission limitations, operating limits, and work practice standards for existing affected sources no later than February 5, 2007, except as provided in paragraphs (b)(2) and (3) of this section.

(2) Floating roof storage tanks at existing affected sources must be in compliance with the work practice standards in Table 4 to this subpart, item 1, at all times after the next degassing and cleaning activity or within 10 years after February 3, 2004, whichever occurs first. If the first degassing and cleaning activity occurs during the 3 years following February 3, 2004, the compliance date is February 5, 2007.

(3)(i) If an addition or change other than reconstruction as defined in §63.2 is made to an existing affected facility that causes the total actual annual facility-level organic liquid loading volume to exceed the criteria for control in Table 2 to this subpart, items 7 and 8, the owner or operator must comply with the transfer rack requirements specified in §63.2346(b) immediately; that is, be in compliance the first day of the period following the end of the 3-year period triggering the control criteria.

(ii) If the owner or operator believes that compliance with the transfer rack emission limits cannot be achieved immediately, as specified in paragraph (b)(3)(i) of this section, the owner or operator may submit a request for a compliance extension, as specified in paragraphs (b)(3)(ii)(A) through (I) of this section. Subject to paragraph (b)(3)(ii)(B) of this section, until an extension of compliance has been granted by the Administrator (or a State with an approved permit program) under this paragraph (b)(3)(ii), the owner or operator of the transfer rack subject to the requirements of this section shall comply with all applicable requirements of this subpart. Advice on requesting an extension of compliance may be obtained from the Administrator (or the State with an approved permit program).

(A) *Submittal.* The owner or operator shall submit a request for a compliance extension to the Administrator (or a State, when the State has an approved 40 CFR part 70 permit program and the source is required to obtain a 40 CFR part 70 permit under that program, or a State, when the State has been delegated the authority to implement and enforce the emission standard for that source) seeking an extension allowing the source up to 1 additional year to comply with the transfer rack standard, if such additional period is necessary for the installation of controls. The owner or operator of the affected source who has requested an extension of compliance under this paragraph (b)(3)(ii)(A) and who is otherwise required to obtain a title V permit shall apply for such permit, or apply to have the source's title V permit revised to incorporate the conditions of the extension of compliance. The conditions of an extension of compliance granted under this paragraph (b)(3)(ii)(A) will be incorporated into the affected source's title V permit according to the provisions of 40 CFR part 70 or Federal title V regulations in this chapter (42 U.S.C. 7661), whichever are applicable.

(B) *When to submit.* (*1*) Any request submitted under paragraph (b)(3)(ii)(A) of this section must be submitted in writing to the appropriate authority no later than 120 days prior to the affected source's compliance date (as specified in paragraph (b)(3)(i) of this section), except as provided for in paragraph (b)(3)(ii)(B)(*2*) of this section. Nonfrivolous requests submitted under this paragraph (b)(3)(ii)(B)(*1*) will stay the applicability of the rule as to the emission points in question until such time as the request is granted or denied. A denial will be effective as of the date of denial.

(*2*) An owner or operator may submit a compliance extension request after the date specified in paragraph (b)(3)(ii)(B)(*1*) of this section provided the need for the compliance extension arose after that date, and before the otherwise applicable compliance date and the need arose due to circumstances beyond reasonable control of the owner or operator. This request must include, in addition to the information required in paragraph (b)(3)(ii)(C) of this section, a statement of the reasons additional time is needed and the date when the owner or operator first learned of the problems. Nonfrivolous requests submitted under this paragraph (b)(3)(ii)(B)(*2*) will stay the applicability of the rule as to the emission points in question until such time as the request is granted or denied. A denial will be effective as of the original compliance date.

(C) *Information required.* The request for a compliance extension under paragraph (b)(3)(ii)(A) of this section shall include the following information:

(*1*) The name and address of the owner or operator and the address of the existing source if it differs from the address of the owner or operator;

(*2*) The name, address, and telephone number of a contact person for further information;

(*3*) An identification of the organic liquid distribution operation and of the specific equipment for which additional compliance time is required;

(*4*) A description of the controls to be installed to comply with the standard;

(*5*) Justification for the length of time being requested; and

(*6*) A compliance schedule, including the date by which each step toward compliance will be reached. At a minimum, the list of dates shall include:

(*i*) The date by which on-site construction, installation of emission control equipment, or a process change is planned to be initiated;

(*ii*) The date by which on-site construction, installation of emission control equipment, or a process change is to be completed; and

(*iii*) The date by which final compliance is to be achieved.

(D) *Approval of request for extension of compliance.* Based on the information provided in any request made under paragraph (b)(3)(ii)(C) of this section, or other information, the Administrator (or the State with an approved permit program) may grant an extension of compliance with the transfer rack emission standard, as specified in paragraph (b)(3)(ii) of this section. The extension will be in writing and will—

(*1*) Identify each affected source covered by the extension;

(*2*) Specify the termination date of the extension;

(*3*) Specify the dates by which steps toward compliance are to be taken, if appropriate;

(*4*) Specify other applicable requirements to which the compliance extension applies (e.g., performance tests);

(*5*) Specify the contents of the progress reports to be submitted and the dates by which such reports are to be submitted, if required pursuant to paragraph (b)(3)(ii)(E) of this section.

(*6*) Under paragraph (b)(3)(ii) of this section, specify any additional conditions that the Administrator (or the State) deems necessary to assure installation of the necessary controls and protection of the health of persons during the extension period.

(E) *Progress reports.* The owner or operator of an existing source that has been granted an extension of compliance under paragraph (b)(3)(ii)(D) of this section may be required to submit to the Administrator (or the State with an approved permit program) progress reports indicating whether the steps toward compliance outlined in the compliance schedule have been reached.

(F) *Notification of approval or intention to deny.* (*1*) The Administrator (or the State with an approved permit program) will notify the owner or operator in writing of approval or intention to deny approval of a request for an extension of compliance within 30 calendar days after receipt of sufficient information to evaluate a request submitted under paragraph (b)(3)(ii) of this section. The Administrator (or the State) will notify the owner or operator in writing of the status of his/her application; that is, whether the application contains sufficient information to make a determination, within 30 calendar days after receipt of the original application and within 30 calendar days after receipt of any supplementary information that is submitted. The 30-day approval or denial period will begin after the owner or operator has been notified in writing that his/her application is complete. Failure by the Administrator to act within 30 calendar days to approve or disapprove a request submitted under paragraph (b)(3)(ii) of this section does not constitute automatic approval of the request.

(*2*) When notifying the owner or operator that his/her application is not complete, the Administrator will specify the information needed to complete the application and provide notice of opportunity for the applicant to present, in writing, within 30 calendar days after he/she is notified of the incomplete application, additional information or arguments to the Administrator to enable further action on the application.

(*3*) Before denying any request for an extension of compliance, the Administrator (or the State with an approved permit program) will notify the owner or operator in writing of the Administrator's (or the State's) intention to issue the denial, together with:

(*i*) Notice of the information and findings on which the intended denial is based; and

(*ii*) Notice of opportunity for the owner or operator to present in writing, within 15 calendar days after he/she is notified of the intended denial, additional information or arguments to the Administrator (or the State) before further action on the request.

(*4*) The Administrator's final determination to deny any request for an extension will be in writing and will set forth the specific grounds on which the denial is based. The final determination will be made within 30 calendar days after presentation of additional information or argument (if the application is complete), or within 30 calendar days after the final date specified for the presentation if no presentation is made.

(G) *Termination of extension of compliance.* The Administrator (or the State with an approved permit program) may terminate an extension of compliance at an earlier date than specified if any specification under paragraph (b)(3)(ii)(D)(*3*) or paragraph (b)(3)(ii)(D)(*4*) of this section is not met. Upon a determination to terminate, the Administrator will notify, in writing, the owner or operator of the Administrator's determination to terminate, together with:

(*1*) Notice of the reason for termination; and

(*2*) Notice of opportunity for the owner or operator to present in writing, within 15 calendar days after he/she is notified of the determination to terminate, additional information or arguments to the Administrator before further action on the termination.

(*3*) A final determination to terminate an extension of compliance will be in writing and will set forth the specific grounds on which the termination is based. The final determination will be made within 30 calendar days after presentation of additional information or arguments, or within 30 calendar days after the final date specified for the presentation if no presentation is made.

(H) The granting of an extension under this section shall not abrogate the Administrator's authority under section 114 of the CAA.

(I) *Limitation on use of compliance extension.* The owner or operator may request an extension of compliance under the provisions specified in paragraph (b)(3)(ii) of this section only once for each facility.

(c) If you have an area source that does not commence reconstruction but increases its emissions or its potential to emit such that it becomes a major source of HAP emissions and an existing affected source subject to this subpart, you must be in compliance by 3 years after the area source becomes a major source.

(d) You must meet the notification requirements in §§63.2343 and 63.2382(a), as applicable, according to the schedules in §63.2382(a) and (b)(1) through (3) and in subpart A of this part. Some of these notifications must be submitted before the compliance dates for the emission limitations, operating limits, and work practice standards in this subpart.

Testing and Initial Compliance Requirements
§ 63.2354 What performance tests, design evaluations, and performance evaluations must I conduct?

(a)(1) For each performance test that you conduct, you must use the procedures specified in subpart SS of this part and the provisions specified in paragraph (b) of this section.

(2) For each design evaluation you conduct, you must use the procedures specified in subpart SS of this part.

(3) For each performance evaluation of a continuous emission monitoring system (CEMS) you conduct, you must follow the requirements in §63.8(e).

(b)(1) For nonflare control devices, you must conduct each performance test according to the requirements in §63.7(e)(1), and either §63.988(b), §63.990(b), or §63.995(b), using the procedures specified in §63.997(e).

(2) You must conduct three separate test runs for each performance test on a nonflare control device as specified in §§63.7(e)(3) and 63.997(e)(1)(v). Each test run must last at least 1 hour, except as provided in §63.997(e)(1)(v)(A) and (B).

(3)(i) In addition to EPA Method 25 or 25A of 40 CFR part 60, appendix A, to determine compliance with the organic HAP or TOC emission limit, you may use EPA Method 18 of 40 CFR part 60, appendix A, as specified in paragraph (b)(3)(i) of this section. As an alternative to EPA Method 18, you may use ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference, see §63.14), under the conditions specified in paragraph (b)(3)(ii) of this section.

(A) If you use EPA Method 18 to measure compliance with the percentage efficiency limit, you must first determine which organic HAP are present in the inlet gas stream (i.e., uncontrolled emissions) using knowledge of the organic liquids or the screening procedure described in EPA Method 18. In conducting the performance test, you must analyze samples collected as specified in EPA Method 18, simultaneously at the inlet and outlet of the control device. Quantify the emissions for the same organic HAP identified as present in the inlet gas stream for both the inlet and outlet gas streams of the control device.

(B) If you use EPA Method 18 of 40 CFR part 60, appendix A, to measure compliance with the emission concentration limit, you must first determine which organic HAP are present in the inlet gas stream using knowledge of the organic liquids or the screening procedure described in EPA Method 18. In conducting the performance test, analyze samples collected as specified in EPA Method 18 at the outlet of the control device. Quantify the control device outlet emission concentration for the same organic HAP identified as present in the inlet or uncontrolled gas stream.

(ii) You may use ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference, see §63.14), as an alternative to EPA Method 18 if the target concentration is between 150 parts per billion by volume and 100 ppmv and either of the conditions specified in paragraph (b)(2)(ii)(A) or (B) of this section exists. For target compounds not listed in Section 1.1 of ASTM D6420–99 (Reapproved 2004) and not amenable to detection by mass spectrometry, you may not use ASTM D6420–99 (Reapproved 2004).

(A) The target compounds are those listed in Section 1.1 of ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference, see §63.14),; or

(B) For target compounds not listed in Section 1.1 of ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference, see §63.14), but potentially detected by mass spectrometry, the additional system continuing calibration check after each run, as detailed in ASTM D6420–99 (Reapproved 2004), Section 10.5.3, must be followed, met, documented, and submitted with the data report, even if there is no moisture condenser used or the compound is not considered water-soluble.

(4) If a principal component of the uncontrolled or inlet gas stream to the control device is formaldehyde, you may use EPA Method 316 of appendix A of this part instead of EPA Method 18 of 40 CFR part 60, appendix A, for measuring the formaldehyde. If formaldehyde is the predominant organic HAP in the inlet gas stream, you may use EPA Method 316 alone to measure formaldehyde either at the inlet and outlet of the control device using the formaldehyde control efficiency as a surrogate for total organic HAP or TOC efficiency, or at the outlet of a combustion device for determining compliance with the emission concentration limit.

(5) You may not conduct performance tests during periods of SSM, as specified in §63.7(e)(1).

(c) To determine the HAP content of the organic liquid, you may use EPA Method 311 of 40 CFR part 63, appendix A, or other method approved by the Administrator. In addition, you may use other means, such as voluntary consensus standards, material safety data sheets (MSDS), or certified product data sheets, to determine the HAP content of the organic liquid. If the method you select to determine the HAP content provides HAP content ranges, you must use the upper end of each HAP content range in determining the total HAP content of the organic liquid. The EPA may require you to test the HAP content of an organic liquid using EPA Method 311 or other method approved by the Administrator. If the results of the EPA Method 311 (or any other approved method) are different from the HAP content determined by another means, the EPA Method 311 (or approved method) results will govern.

Notifications, Reports, and Records

§ 63.2382 What notifications must I submit and when and what information should be submitted?

(a) You must submit each notification in subpart SS of this part, Table 12 to this subpart, and paragraphs (b) through (d) of this section that applies to you. You must submit these notifications according to the schedule in Table 12 to this subpart and as specified in paragraphs (b) through (d) of this section.

(b)(1) *Initial Notification.* If you startup your affected source before February 3, 2004, you must submit the Initial Notification no later than 120 calendar days after February 3, 2004.

(2) If you startup your new or reconstructed affected source on or after February 3, 2004, you must submit the Initial Notification no later than 120 days after initial startup.

(c) If you are required to conduct a performance test, you must submit the Notification of Intent to conduct the test at least 60 calendar days before it is initially scheduled to begin as required in §63.7(b)(1).

(d)(1) *Notification of Compliance Status.* If you are required to conduct a performance test, design evaluation, or other initial compliance demonstration as specified in Table 5, 6, or 7 to this subpart, you must submit a Notification of Compliance Status.

(2) The Notification of Compliance Status must include the information required in §63.999(b) and in paragraphs (d)(2)(i) through (viii) of this section.

(i) The results of any applicability determinations, emission calculations, or analyses used to identify and quantify organic HAP emissions from the affected source.

(ii) The results of emissions profiles, performance tests, engineering analyses, design evaluations, flare compliance assessments, inspections and repairs, and calculations used to demonstrate initial compliance according to Tables 6 and 7 to this subpart. For performance tests, results must include descriptions of sampling and analysis procedures and quality assurance procedures.

(iii) Descriptions of monitoring devices, monitoring frequencies, and the operating limits established during the initial compliance demonstrations, including data and calculations to support the levels you establish.

(iv) Descriptions of worst-case operating and/or testing conditions for the control device(s).

(v) Identification of emission sources subject to overlapping requirements described in §63.2396 and the authority under which you will comply.

(vi) The applicable information specified in §63.1039(a)(1) through (3) for all pumps and valves subject to the work practice standards for equipment leak components in Table 4 to this subpart, item 4.

(vii) If you are complying with the vapor balancing work practice standard for transfer racks according to Table 4 to this subpart, item 3.a, include a statement to that effect and a statement that the pressure vent settings on the affected storage tanks are greater than or equal to 2.5 psig.

(viii) The information specified in §63.2386(c)(10)(i), unless the information has already been submitted with the first Compliance report. If the information specified in §63.2386(c)(10)(i) has already been submitted with the first Compliance report, the information specified in §63.2386(d)(3) and (4), as applicable, shall be submitted instead.

§ 63.2386 What reports must I submit and when and what information is to be submitted in each?

(a) You must submit each report in subpart SS of this part, Table 11 to this subpart, Table 12 to this subpart, and in paragraphs (c) through (e) of this section that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report according to Table 11 to this subpart and by the dates shown in paragraphs (b)(1) through (3) of this section, by the dates shown in subpart SS of this part, and by the dates shown in Table 12 to this subpart, whichever are applicable.

(1)(i) The first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.2342 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your affected source in §63.2342.

(ii) The first Compliance report must be postmarked no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.2342.

(2)(i) Each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(ii) Each subsequent Compliance report must be postmarked no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(3) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) and (2) of this section.

(c) ***First Compliance report.*** **The first Compliance report must contain the information specified in paragraphs (c)(1) through (10) of this section.**

(1) Company name and address.

(2) Statement by a responsible official, including the official's name, title, and signature, certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

(3) Date of report and beginning and ending dates of the reporting period.

(4) Any changes to the information listed in §63.2382(d)(2) that have occurred since the submittal of the Notification of Compliance Status.

(5) If you had a SSM during the reporting period and you took actions consistent with your SSM plan, the Compliance report must include the information described in §63.10(d)(5)(i).

(6) If there are no deviations from any emission limitation or operating limit that applies to you and there are no deviations from the requirements for work practice standards, a statement that there were no deviations from the emission limitations, operating limits, or work practice standards during the reporting period.

(7) If there were no periods during which the CMS was out of control as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out of control during the reporting period.

(8) For closed vent systems and control devices used to control emissions, the information specified in paragraphs (c)(8)(i) and (ii) of this section for those planned routine maintenance activities that would require the control device to not meet the applicable emission limit.

(i) A description of the planned routine maintenance that is anticipated to be performed for the control device during the next 6 months. This description must include the type of maintenance necessary, planned frequency of maintenance, and lengths of maintenance periods.

(ii) A description of the planned routine maintenance that was performed for the control device during the previous 6 months. This description must include the type of maintenance performed and the total number of hours during those 6 months that the control device did not meet the applicable emission limit due to planned routine maintenance.

(9) A listing of all transport vehicles into which organic liquids were loaded at transfer racks that are subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10, during the previous 6 months for which vapor tightness documentation as required in §63.2390(c) was not on file at the facility.

(10)(i) A listing of all transfer racks (except those racks at which only unloading of organic liquids occurs) and of tanks greater than or equal to 18.9 cubic meters (5,000 gallons) that are part of the affected source but are not subject to any of the emission limitations, operating limits, or work practice standards of this subpart.

(ii) If the information specified in paragraph (c)(10)(i) of this section has already been submitted with the Notification of Compliance Status, the information specified in paragraphs (d)(3) and (4) of this section, as applicable, shall be submitted instead.

(d) ***Subsequent Compliance reports*** **. Subsequent Compliance reports must contain the information in paragraphs (c)(1) through (9) of this section and, where applicable, the information in paragraphs (d)(1) through (4) of this section.**

(1) For each deviation from an emission limitation occurring at an affected source where you are using a CMS to comply with an emission limitation in this subpart, you must include in the Compliance report the applicable information in paragraphs (d)(1)(i) through (xii) of this section. This includes periods of SSM.

(i) The date and time that each malfunction started and stopped.

(ii) The dates and times that each CMS was inoperative, except for zero (low-level) and high-level checks.

(iii) For each CMS that was out of control, the information in §63.8(c)(8).

(iv) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of SSM, or during another period.

(v) A summary of the total duration of the deviations during the reporting period, and the total duration as a percentage of the total emission source operating time during that reporting period.

(vi) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(vii) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percentage of the total emission source operating time during that reporting period.

(viii) An identification of each organic HAP that was potentially emitted during each deviation based on the known organic HAP contained in the liquid(s).

(ix) A brief description of the emission source(s) at which the CMS deviation(s) occurred.

(x) A brief description of each CMS that was out of control during the period.

(xi) The date of the latest certification or audit for each CMS.

(xii) A brief description of any changes in CMS, processes, or controls since the last reporting period.

(2) Include in the Compliance report the information in paragraphs (d)(2)(i) through (iii) of this section, as applicable.

(i) For each storage tank and transfer rack subject to control requirements, include periods of planned routine maintenance during which the control device did not comply with the applicable emission limits in table 2 to this subpart.

(ii) For each storage tank controlled with a floating roof, include a copy of the inspection record (required in §63.1065(b)) when inspection failures occur.

(iii) If you elect to use an extension for a floating roof inspection in accordance with §63.1063(c)(2)(iv)(B) or (e)(2), include the documentation required by those paragraphs.

(3)(i) A listing of any storage tank that became subject to controls based on the criteria for control specified in table 2 to this subpart, items 1 through 6, since the filing of the last Compliance report.

(ii) A listing of any transfer rack that became subject to controls based on the criteria for control specified in table 2 to this subpart, items 7 through 10, since the filing of the last Compliance report.

(4)(i) A listing of tanks greater than or equal to 18.9 cubic meters (5,000 gallons) that became part of the affected source but are not subject to any of the emission limitations, operating limits, or work practice standards of this subpart, since the last Compliance report.

(ii) A listing of all transfer racks (except those racks at which only the unloading of organic liquids occurs) that became part of the affected source but are not subject to any of the emission limitations, operating limits, or work practice standards of this subpart, since the last Compliance report.

(e) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to table 11 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission limitation in this subpart, we will consider submission of the Compliance report as satisfying any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report will not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the applicable title V permitting authority.

§ 63.2390 What records must I keep?

(a) For each emission source identified in §63.2338 that does not require control under this subpart, you must keep all records identified in §63.2343.

(b) For each emission source identified in §63.2338 that does require control under this subpart:

(1) You must keep all records identified in subpart SS of this part and in table 12 to this subpart that are applicable, including records related to notifications and reports, SSM, performance tests, CMS, and performance evaluation plans; and

(2) You must keep the records required to show continuous compliance, as required in subpart SS of this part and in tables 8 through 10 to this subpart, with each emission limitation, operating limit, and work practice standard that applies to you.

(c) For each transport vehicle into which organic liquids are loaded at a transfer rack that is subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10, you must keep the applicable records in paragraphs (c)(1) and (2) of this section or alternatively the verification records in paragraph (c)(3) of this section.

(1) For transport vehicles equipped with vapor collection equipment, the documentation described in 40 CFR 60.505(b), except that the test title is: Transport Vehicle Pressure Test-EPA Reference Method 27.

(2) For transport vehicles without vapor collection equipment, current certification in accordance with the U.S. DOT pressure test requirements in 49 CFR part 180 for cargo tanks or 49 CFR 173.31 for tank cars.

(3) In lieu of keeping the records specified in paragraph (c)(1) or (2) of this section, as applicable, the owner or operator shall record that the verification of U.S. DOT tank certification or Method 27 of appendix A to 40 CFR part 60 testing, required in table 5 to this subpart, item 2, has been performed. Various methods for the record of verification can be used, such as: A check-off on a log sheet, a list of U.S. DOT serial numbers or Method 27 data, or a position description for gate security showing that the security guard will not allow any trucks on site that do not have the appropriate documentation.

(d) You must keep records of the total actual annual facility-level organic liquid loading volume as defined in §63.2406 through transfer racks to document the applicability, or lack thereof, of the emission limitations in table 2 to this subpart, items 7 through 10.

(e) An owner or operator who elects to comply with §63.2346(a)(4) shall keep the records specified in paragraphs (e)(1) through (3) of this section.

(1) A record of the U.S. DOT certification required by §63.2346(a)(4)(ii).

(2) A record of the pressure relief vent setting specified in §63.2348(a)(4)(v).

(3) If complying with §63.2348(a)(4)(vi)(B), keep the records specified in paragraphs (e)(3)(i) and (ii) of this section.

(i) A record of the equipment to be used and the procedures to be followed when reloading the cargo tank or tank car and displacing vapors to the storage tank from which the liquid originates.

(ii) A record of each time the vapor balancing system is used to comply with §63.2348(a)(4)(vi)(B).

§ 63.2394 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious inspection and review according to §63.10(b)(1), including records stored in electronic form at a separate location.

(b) As specified in §63.10(b)(1), you must keep your files of all information (including all reports and notifications) for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You may keep the records off site for the remaining 3 years.

§ 63.2398 What parts of the General Provisions apply to me?

Table 12 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§ 63.2402 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. Environmental Protection Agency (U.S. EPA) or a delegated authority such as your State, local, or eligible tribal agency. If the EPA Administrator has delegated authority to your State, local, or eligible tribal agency, then that agency, as well as the EPA, has the authority to implement and enforce this subpart. You should contact your EPA Regional Office (see list in §63.13) to find out if this subpart is delegated to your State, local, or eligible tribal agency.

(b) In delegating implementation and enforcement authority for this subpart to a State, local, or eligible tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not delegated to the State, local, or eligible tribal agency.

(1) Approval of alternatives to the nonopacity emission limitations, operating limits, and work practice standards in §63.2346(a) through (c) under §63.6(g).

(2) Approval of major changes to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major changes to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major changes to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

§ 63.2406 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in §63.2, 40 CFR part 63, subparts H, PP, SS, TT, UU, and WW, and in this section. If the same term is defined in another subpart and in this section, it will have the meaning given in this section for purposes of this subpart. Notwithstanding the introductory language in §63.921, the terms "container" and "safety device" shall have the meaning found in this subpart and not in §63.921.

***Actual annual average temperature,* for organic liquids, means the temperature determined using the following methods:**

(1) For heated or cooled storage tanks, use the calculated annual average temperature of the stored organic liquid as determined from a design analysis of the storage tank.

(2) For ambient temperature storage tanks:

(i) Use the annual average of the local (nearest) normal daily mean temperatures reported by the National Climatic Data Center; or

(ii) Use any other method that the EPA approves.

***Annual average true vapor pressure* means the equilibrium partial pressure exerted by the total table 1 organic HAP in the stored or transferred organic liquid. For the purpose of determining if a liquid meets the definition of an organic liquid, the vapor pressure is determined using standard conditions of 77 degrees F and 29.92 inches of mercury. For the purpose of determining whether an organic liquid meets the applicability criteria in table 2, items 1 through 6, to this subpart, use the actual annual average temperature as defined in this subpart. The vapor pressure value in either of these cases is determined:**

(1) In accordance with methods described in American Petroleum Institute Publication 2517, Evaporative Loss from External Floating-Roof Tanks (incorporated by reference, see §63.14);

(2) Using standard reference texts;

(3) By the American Society for Testing and Materials Method D2879–83, 96 (incorporated by reference, see §63.14); or

(4) Using any other method that the EPA approves.

***Bottoms receiver* means a tank that collects distillation bottoms before the stream is sent for storage or for further processing downstream.**

Cargo tank **means a liquid-carrying tank permanently attached and forming an integral part of a motor vehicle or truck trailer. This term also refers to the entire cargo tank motor vehicle or trailer. For the purpose of this subpart, vacuum trucks used exclusively for maintenance or spill response are not considered cargo tanks.**

Closed vent system **means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapors from an emission point to a control device. This system does not include the vapor collection system that is part of some transport vehicles or the loading arm or hose that is used for vapor return. For transfer racks, the closed vent system begins at, and includes, the first block valve on the downstream side of the loading arm or hose used to convey displaced vapors.**

Combustion device **means an individual unit of equipment, such as a flare, oxidizer, catalytic oxidizer, process heater, or boiler, used for the combustion of organic emissions.**

Container **means a portable unit in which a material can be stored, transported, treated, disposed of, or otherwise handled. Examples of containers include, but are not limited to, drums and portable cargo containers known as "portable tanks" or "totes."**

Control device **means any combustion device, recovery device, recapture device, or any combination of these devices used to comply with this subpart. Such equipment or devices include, but are not limited to, absorbers, adsorbers, condensers, and combustion devices. Primary condensers, steam strippers, and fuel gas systems are not considered control devices.**

Crude oil **means any of the naturally occurring liquids commonly referred to as crude oil, regardless of specific physical properties. Only those crude oils downstream of the first point of custody transfer after the production field are considered crude oils in this subpart.**

Custody transfer **means the transfer of hydrocarbon liquids after processing and/or treatment in the producing operations, or from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.**

Design evaluation **means a procedure for evaluating control devices that complies with the requirements in §63.985(b)(1)(i).**

Deviation **means any instance in which an affected source subject to this subpart, or portion thereof, or an owner or operator of such a source:**

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limitation (including any operating limit) or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart, and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation (including any operating limit) or work practice standard in this subpart during SSM.

Emission limitation **means an emission limit, opacity limit, operating limit, or visible emission limit.**

Equipment leak component **means each pump, valve, and sampling connection system used in organic liquids service at an OLD operation. Valve types include control, globe, gate, plug, and ball. Relief and check valves are excluded.**

Gasoline **means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals (4.0 pounds per square inch absolute (psia)) or greater which is used as a fuel for internal combustion engines. Aviation gasoline is included in this definition.**

High throughput transfer rack **means those transfer racks that transfer into transport vehicles (for existing affected sources) or into transport vehicles and containers (for new affected sources) a total of 11.8 million liters per year or greater of organic liquids.**

In organic liquids service **means that an equipment leak component contains or contacts organic liquids having 5 percent by weight or greater of the organic HAP listed in Table 1 to this subpart.**

Low throughput transfer rack **means those transfer racks that transfer into transport vehicles (for existing affected sources) or into transport vehicles and containers (for new affected sources) less than 11.8 million liters per year of organic liquids.**

On-site **or** ***on site*** **means, with respect to records required to be maintained by this subpart or required by another subpart referenced by this subpart, that records are stored at a location within a major source which encompasses the affected source. On-site includes, but is not limited to, storage at the affected source to which the records pertain, storage in central files elsewhere at the major source, or electronically available at the site.**

Organic liquid **means:**

(1) Any non-crude oil liquid or liquid mixture that contains 5 percent by weight or greater of the organic HAP listed in Table 1 to this subpart, as determined using the procedures specified in §63.2354(c).

(2) Any crude oils downstream of the first point of custody transfer.

(3) Organic liquids for purposes of this subpart do not include the following liquids:

(i) Gasoline (including aviation gasoline), kerosene (No. 1 distillate oil), diesel (No. 2 distillate oil), asphalt, and heavier distillate oils and fuel oils;

(ii) Any fuel consumed or dispensed on the plant site directly to users (such as fuels for fleet refueling or for refueling marine vessels that support the operation of the plant);

(iii) Hazardous waste;

(iv) Wastewater;

(v) Ballast water: or

(vi) Any non-crude oil liquid with an annual average true vapor pressure less than 0.7 kilopascals (0.1 psia).

Organic liquids distribution (OLD) operation **means the combination of activities and equipment used to store or transfer organic liquids into, out of, or within a plant site regardless of the specific activity being performed. Activities include, but are not limited to, storage, transfer, blending, compounding, and packaging.**

Permitting authority **means one of the following:**

(1) The State Air Pollution Control Agency, local agency, or other agency authorized by the EPA Administrator to carry out a permit program under 40 CFR part 70; or

(2) The EPA Administrator, in the case of EPA-implemented permit programs under title V of the CAA (42 U.S.C. 7661) and 40 CFR part 71.

Plant site **means all contiguous or adjoining surface property that is under common control, including surface properties that are separated only by a road or other public right-of-way. Common control includes surface properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination.**

Research and development facility **means laboratory and pilot plant operations whose primary purpose is to conduct research and development into new processes and products, where the operations are under the close supervision of technically trained personnel, and which are not engaged in the manufacture of products for commercial sale, except in a** ***de minimis*** **manner.**

Responsible official **means responsible official as defined in 40 CFR 70.2 and 40 CFR 71.2, as applicable.**

Safety device **means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device that functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event.**

Shutdown **means the cessation of operation of an OLD affected source, or portion thereof (other than as part of normal operation of a batch-type operation), including equipment required or used to comply with this subpart, or the emptying and degassing of a storage tank. Shutdown as defined here includes, but is not limited to, events that result from periodic maintenance, replacement of equipment, or repair.**

Startup **means the setting in operation of an OLD affected source, or portion thereof (other than as part of normal operation of a batch-type operation), for any purpose. Startup also includes the placing in operation of any individual piece of equipment required or used to comply with this subpart including, but not limited to, control devices and monitors.**

Storage tank **means a stationary unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, or reinforced plastic) that provide structural support and is designed to hold a bulk quantity of liquid. Storage tanks do not include:**

(1) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;

(2) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;

(3) Bottoms receivers;

(4) Surge control vessels;

(5) Vessels storing wastewater; or

(6) Reactor vessels associated with a manufacturing process unit.

Surge control vessel **means feed drums, recycle drums, and intermediate vessels. Surge control vessels are used within chemical manufacturing processes when in-process storage, mixing, or management of flow rates or volumes is needed to assist in production of a product.**

Tank car **means a car designed to carry liquid freight by rail, and including a permanently attached tank.**

Total actual annual facility-level organic liquid loading volume **means the total facility-level actual volume of organic liquid loaded for transport within or out of the facility through transfer racks that are part of the affected source into transport vehicles (for existing affected sources) or into transport vehicles and containers (for new affected sources) based on a 3-year rolling average, calculated annually.**

(1) For existing affected sources, each 3-year rolling average is based on actual facility-level loading volume during each calendar year (January 1 through December 31) in the 3-year period. For calendar year 2004 only (the first year of the initial 3-year rolling average), if an owner or operator of an affected source does not have actual loading volume data for the time period from January 1, 2004, through February 2, 2004 (the time period prior to the effective date of the OLD NESHAP), the owner or operator shall compute a facility-level loading volume for this time period as follows: At the end of the 2004 calendar year, the owner or operator shall calculate a daily average facility-level loading volume (based on the actual loading volume for February 3, 2004, through December 31, 2004) and use that daily average to estimate the facility-level loading volume for the period of time from January 1, 2004, through February 2, 2004. The owner or operator shall then sum the estimated facility-level loading volume from January 1, 2004, through February 2, 2004, and the actual facility-level loading volume from February 3, 2004, through December 31, 2004, to calculate the annual facility-level loading volume for calendar year 2004.

(2)(i) For new affected sources, the 3-year rolling average is calculated as an average of three 12-month periods. An owner or operator must select as the beginning calculation date with which to start the calculations as either the initial startup date of the new affected source or the first day of the calendar month following the month in which startup occurs. Once selected, the date with which the calculations begin cannot be changed.

(ii) The initial 3-year rolling average is based on the projected maximum facility-level annual loading volume for each of the 3 years following the selected beginning calculation date. The second 3-year rolling average is based on actual facility-level loading volume for the first year of operation plus a new projected maximum facility-level annual loading volume for second and third years following the selected beginning calculation date. The third 3-year rolling average is based on actual facility-level loading volume for the first 2 years of operation plus a new projected maximum annual facility-level loading volume for the third year following the beginning calculation date. Subsequent 3-year rolling averages are based on actual facility-level loading volume for each year in the 3-year rolling average.

Transfer rack **means a single system used to load organic liquids into, or unload organic liquids out of, transport vehicles or containers. It includes all loading and unloading arms, pumps, meters, shutoff valves, pressure relief discharges, and other piping and equipment necessary for the transfer operation. Transfer equipment and operations that are physically separate (i.e., do not share common piping, valves, and other equipment) are considered to be separate transfer racks.**

Transport vehicle **means a cargo tank or tank car.**

Vapor balancing system **means:**

(1) A piping system that collects organic HAP vapors displaced from transport vehicles or containers during loading and routes the collected vapors to the storage tank from which the liquid being loaded originated or to another storage tank connected to a common header. For containers, the piping system must route the displaced vapors directly to the appropriate storage tank or to another storage tank connected to a common header in order to qualify as a vapor balancing system; or

(2) A piping system that collects organic HAP vapors displaced from the loading of a storage tank and routes the collected vapors to the transport vehicle from which the storage tank is filled.

Vapor collection system **means any equipment located at the source (i.e., at the OLD operation) that is not open to the atmosphere; that is composed of piping, connections, and, if necessary, flow-inducing devices; and that is used for:**

(1) Containing and conveying vapors displaced during the loading of transport vehicles to a control device;

(2) Containing and directly conveying vapors displaced during the loading of containers; or

(3) Vapor balancing. This does not include any of the vapor collection equipment that is installed on the transport vehicle.

Vapor-tight transport vehicle **means a transport vehicle that has been demonstrated to be vapor-tight. To be considered vapor-tight, a transport vehicle equipped with vapor collection equipment must undergo a pressure change of no more than 250 pascals (1 inch of water) within 5 minutes after it is pressurized to 4,500 pascals (18 inches of water). This capability must be demonstrated annually using the procedures specified in EPA Method 27 of 40 CFR part 60, appendix A. For all other transport vehicles, vapor tightness is demonstrated by performing the U.S. DOT pressure test procedures for tank cars and cargo tanks.**

Work practice standard **means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.**

Table 1 to Subpart EEEE of Part 63—Organic Hazardous Air Pollutants

You must use the organic HAP information listed in the following table to determine which of the liquids handled at your facility meet the HAP content criteria in the definition of Organic Liquid in §63.2406.

Compound name	CAS No.[1]
2,4-D salts and esters	94–75–7
Acetaldehyde	75–07–0
Acetonitrile	75–05–8

Compound name	CAS No.[1]
Acetophenone	98–86–2
Acrolein	107–02–8
Acrylamide	79–06–1
Acrylic acid	79–10–7
Acrylonitrile	107–13–1
Allyl chloride	107–05–1
Aniline	62–53–3
Benzene	71–43–2
Biphenyl	92–52–4
Butadiene (1,3-)	106–99–0
Carbon tetrachloride	56–23–5
Chloroacetic acid	79–11–8
Chlorobenzene	108–90–7
2-Chloro-1,3-butadiene (Chloroprene)	126–99–8
Chloroform	67–66–3
m-Cresol	108–39–4
o-Cresol	95–48–7
p-Cresol	106–44–5
Cresols/cresylic acid	1319–77–3
Cumene	98–82–8
Dibenzofurans	132–64–9
Dibutylphthalate	84–74–2
Dichloroethane (1,2-) (Ethylene dichloride) (EDC)	107–06–2
Dichloropropene (1,3-)	542–75–6
Diethanolamine	111–42–2
Diethyl aniline (N,N-)	121–69–7
Diethylene glycol monobutyl ether	112–34–5
Diethylene glycol monomethyl ether	111–77–3
Diethyl sulfate	64–67–5
Dimethyl formamide	68–12–2
Dimethylhydrazine (1,1-)	57–14–7
Dioxane (1,4-) (1,4-Diethyleneoxide)	123–91–1
Epichlorohydrin (1-Chloro-2,3-epoxypropane)	106–89–8
Epoxybutane (1,2-)	106–88–7
Ethyl acrylate	140–88–5

Compound name	CAS No.[1]
Ethylbenzene	100–41–4
Ethyl chloride (Chloroethane)	75–00–3
Ethylene dibromide (Dibromomethane)	106–93–4
Ethylene glycol	107–21–1
Ethylene glycol dimethyl ether	110–71–4
Ethylene glycol monomethyl ether	109–86–4
Ethylene glycol monomethyl ether acetate	110–49–6
Ethylene glycol monophenyl ether	122–99–6
Ethylene oxide	75–21–8
Ethylidene dichloride (1,1-Dichloroethane)	75–34–3
Formaldehyde	50–00–0
Hexachloroethane	67–72–1
Hexane	110–54–3
Hydroquinone	123–31–9
Isophorone	78–59–1
Maleic anhydride	108–31–6
Methanol	67–56–1
Methyl chloride (Chloromethane)	74–87–3
Methylene chloride (Dichloromethane)	75–09–2
Methylenedianiline (4,4′-)	101–77–9
Methylene diphenyl diisocyanate	101–68–8
Methyl hydrazine	60–34–4
Methyl isobutyl ketone (Hexone) (MIBK)	108–10–1
Methyl methacrylate	80–62–6
Methyl tert-butyl ether (MTBE)	1634–04–4
Naphthalene	91–20–3
Nitrobenzene	98–95–3
Phenol	108–9–52
Phthalic anhydride	85–44–9
Polycyclic organic matter	50–32–8
Propionaldehyde	123–38–6
Propylene dichloride (1,2-Dichloropropane)	78–87–5
Propylene oxide	75–56–9
Quinoline	91–22–5
Styrene	100–42–5

Compound name	CAS No.[1]
Styrene oxide	96–09–3
Tetrachloroethane (1,1,2,2-)	79–34–5
Tetrachloroethylene (Perchloroethylene)	127–18–4
Toluene	108–88–3
Toluene diisocyanate (2,4-)	584–84–9
o-Toluidine	95–53–4
Trichlorobenzene (1,2,4-)	120–82–1
Trichloroethane (1,1,1-) (Methyl chloroform)	71–55–6
Trichloroethane (1,1,2-) (Vinyl trichloride)	79–00–5
Trichloroethylene	79–01–6
Triethylamine	121–44–8
Trimethylpentane (2,2,4-)	540–84–1
Vinyl acetate	108–05–4
Vinyl chloride (Chloroethylene)	75–01–4
Vinylidene chloride (1,1-Dichloroethylene)	75–35–4
Xylene (m-)	108–38–3
Xylene (o-)	95–47–6
Xylene (p-)	106–42–3
Xylenes (isomers and mixtures)	1330–20–7

Table 12 to Subpart EEEE of Part 63—Applicability of General Provisions to Subpart EEEE

As stated in §§63.2382 and 63.2398, you must comply with the applicable General Provisions requirements as follows:

Citation	Subject	Brief description	Applies to subpart EEEE
§63.1	Applicability	Initial applicability determination; Applicability after standard established; Permit requirements; Extensions, Notifications	Yes.
§63.2	Definitions	Definitions for part 63 standards	Yes.
§63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.
§63.4	Prohibited Activities and Circumvention	Prohibited activities; Circumvention, Severability	Yes.
§63.5	Construction/Reconstruction	Applicability; Applications; Approvals	Yes.
§63.6(a)	Compliance with Standards/O&M Applicability	GP apply unless compliance extension; GP apply to area sources that become major	Yes.
§63.6(b)(1)–(4)	Compliance Dates for New and Reconstructed Sources	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or	Yes.

Citation	Subject	Brief description	Applies to subpart EEEE
		reconstruction commences for section 112(f)	
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.
§63.6(b)(6)	[Reserved].		
§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source	Yes.
§63.6(c)(1)–(2)	Compliance Dates for Existing Sources	Comply according to date in this subpart, which must be no later than 3 years after effective date; for section 112(f) standards, comply within 90 days of effective date unless compliance extension	Yes.
§63.6(c)(3)–(4)	[Reserved].		
§63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Area sources that become major must comply with major source standards by date indicated in this subpart or by equivalent time period (*e.g* ., 3 years)	Yes.
§63.6(d)	[Reserved].		
§63.6(e)(1)	Operation & Maintenance	Operate to minimize emissions at all times; correct malfunctions as soon as practicable; and operation and maintenance requirements independently enforceable; information Administrator will use to determine if operation and maintenance requirements were met	Yes.
§63.6(e)(2)	[Reserved].		
§63.6(e)(3)	SSM Plan	Requirement for SSM plan; content of SSM plan; actions during SSM	Yes; however, (1) the 2-day reporting requirement in paragraph §63.6(e)(3)(iv) does not apply and (2) §63.6(e)(3) does not apply to emissions sources not requiring control.
§63.6(f)(1)	Compliance Except During SSM	You must comply with emission standards at all times except during SSM	Yes.
§63.6(f)(2)–(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection	Yes.
§63.6(g)(1)–(3)	Alternative Standard	Procedures for getting an alternative standard	Yes.

Citation	Subject	Brief description	Applies to subpart EEEE
§63.6(h)	Opacity/Visible Emission Standards	Requirements for compliance with opacity and visible emission standards	No; except as it applies to flares for which Method 22 observations are required as part of a flare compliance assessment.
§63.6(i)(1)–(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension	Yes.
§63.6(j)	Presidential Compliance Exemption	President may exempt any source from requirement to comply with this subpart	Yes.
§63.7(a)(2)	Performance Test Dates	Dates for conducting initial performance testing; must conduct 180 days after compliance date	Yes.
§63.7(a)(3)	Section 114 Authority	Adminsitrator may require a performance test under CAA section 114 at any time	Yes.
§63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test	Yes.
§63.7(b)(2)	Notification of Rescheduling	If you have to reschedule performance test, must notify Administrator of rescheduled date as soon as practicable and without delay	Yes.
§63.7(c)	Quality Assurance (QA)/Test Plan	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with; test plan approval procedures; performance audit requirements; internal and external QA procedures for testing	Yes.
§63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
§63.7(e)(1)	Conditions for Conducting Performance Tests	Performance tests must be conducted under representative conditions; cannot conduct performance tests during SSM	Yes.
§63.7(e)(2)	Conditions for Conducting Performance Tests	Must conduct according to this subpart and EPA test methods unless Administrator approves alternative	Yes.
§63.7(e)(3)	Test Run Duration	Must have three test runs of at least 1 hour each; compliance is based on arithmetic mean of three runs; conditions when data from an additional test run can be used	Yes; however, for transfer racks per §§63.987(b)(3)(i)(A)–(B) and 63.997(e)(1)(v)(A)–(B) provide exceptions to the requirement for test runs to be at least 1 hour each.
§63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an intermediate or major change, or	Yes.

Citation	Subject	Brief description	Applies to subpart EEEE
		alternative to a test method	
§63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report; must submit performance test data 60 days after end of test with the Notification of Compliance Status; keep data for 5 years	Yes; however, performance test data is to be submitted with the Notification of Compliance Status according to the schedule specified in §63.9(h)(1)–(6) below.
§63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test	Yes.
§63.8(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard	Yes.
§63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of 40 CFR part 60 apply	Yes.
§63.8(a)(3)	[Reserved].		
§63.8(a)(4)	Monitoring of Flares	Monitoring requirements for flares in §63.11	Yes; however, monitoring requirements in §63.987(c) also apply.
§63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative	Yes.
§63.8(b)(2)–(3)	Multiple Effluents and Multiple Monitoring Systems	Specific requirements for installing monitoring systems; must install on each affected source or after combined with another affected source before it is released to the atmosphere provided the monitoring is sufficient to demonstrate compliance with the standard; if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup	Yes.
§63.8(c)(1)	Monitoring System Operation and Maintenance	Maintain monitoring system in a manner consistent with good air pollution control practices	Yes.
§63.8(c)(1)(i)—(iii)	Routine and Predictable SSM	Keep parts for routine repairs readily available; reporting requirements for SSM when action is described in SSM plan.	Yes.
§63.8(c)(2)–(3)	Monitoring System Installation	Must install to get representative emission or parameter measurements; must verify operational status before or at performance test	Yes.
§63.8(c)(4)	CMS Requirements	CMS must be operating except during breakdown, out-of control, repair, maintenance, and high-level calibration drifts; COMS must have a minimum of one cycle of sampling	Yes; however, COMS are not applicable.

Citation	Subject	Brief description	Applies to subpart EEEE
		and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period; CEMS must have a minimum of one cycle of operation for each successive 15-minute period	
§63.8(c)(5)	COMS Minimum Procedures	COMS minimum procedures	No.
§63.8(c)(6)–(8)	CMS Requirements	Zero and high level calibration check requirements. Out-of-control periods	Yes, but only applies for CEMS. 40 CFR part 63, subpart SS provides requirements for CPMS.
§63.8(d)	CMS Quality Control	Requirements for CMS quality control, including calibration, etc.; must keep quality control plan on record for 5 years; keep old versions for 5 years after revisions	Yes, but only applies for CEMS. 40 CFR part 63, subpart SS provides requirements for CPMS.
§63.8(e)	CMS Performance Evaluation	Notification, performance evaluation test plan, reports	Yes, but only applies for CEMS.
§63.8(f)(1)–(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring	Yes, but 40 CFR part 63, subpart SS also provides procedures for approval of CPMS.
§63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for CEMS	Yes.
§63.8(g)	Data Reduction	COMS 6-minute averages calculated over at least 36 evenly spaced data points; CEMS 1 hour averages computed over at least 4 equally spaced data points; data that cannot be used in average	Yes; however, COMS are not applicable.
§63.9(a)	Notification Requirements	Applicability and State delegation	Yes.
§63.9(b)(1)–(2), (4)–(5)	Initial Notifications	Submit notification within 120 days after effective date; notification of intent to construct/reconstruct, notification of commencement of construction/reconstruction, notification of startup; contents of each	Yes.
§63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed best available control technology or lowest achievable emission rate (BACT/LAER)	Yes.
§63.9(d)	Notification of Special Compliance Requirements for New Sources	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date	Yes.
§63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	Yes.

Citation	Subject	Brief description	Applies to subpart EEEE
§63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.
§63.9(g)	Additional Notifications When Using CMS	Notification of performance evaluation; notification about use of COMS data; notification that exceeded criterion for relative accuracy alternative	Yes; however, there are no opacity standards.
§63.9(h)(1)–(6)	Notification of Compliance Status	Contents due 60 days after end of performance test or other compliance demonstration, except for opacity/visible emissions, which are due 30 days after; when to submit to Federal vs. State authority	Yes; however, (1) there are no opacity standards and (2) all initial Notification of Compliance Status, including all performance test data, are to be submitted at the same time, either within 240 days after the compliance date or within 60 days after the last performance test demonstrating compliance has been completed, whichever occurs first.
§63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change in when notifications must be submitted	Yes.
§63.9(j)	Change in Previous Information	Must submit within 15 days after the change	No. These changes will be reported in the first and subsequent compliance reports.
§63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension; when to submit to Federal vs. State authority; procedures for owners of more than one source	Yes.
§63.10(b)(1)	Recordkeeping/Reporting	General requirements; keep all records readily available; keep for 5 years	Yes.
§63.10(b)(2)(i)–(iv)	Records Related to Startup, Shutdown, and Malfunction	Occurrence of each for operations (process equipment); occurrence of each malfunction of air pollution control equipment; maintenance on air pollution control equipment; actions during SSM	Yes.
§63.10(b)(2)(vi)–(xi)	CMS Records	Malfunctions, inoperative, out-of-control periods	Yes.
§63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test	Yes.
§63.10(b)(2)(xiv)	Records	All documentation supporting initial notification and notification of compliance status	Yes.
§63.10(b)(3)	Records	Applicability determinations	Yes.

Citation	Subject	Brief description	Applies to subpart EEEE
§63.10(c)	Records	Additional records for CMS	Yes.
§63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§63.10(d)(2)	Report of Performance Test Results	When to submit to Federal or State authority	Yes.
§63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	Yes.
§63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension	Yes.
§63.10(d)(5)	SSM Reports	Contents and submission	Yes.
§63.10(e)(1)–(2)	Additional CMS Reports	Must report results for each CEMS on a unit; written copy of CMS performance evaluation; 2–3 copies of COMS performance evaluation	Yes; however, COMS are not applicable.
§63.10(e)(3)(i)–(iii)	Reports	Schedule for reporting excess emissions and parameter monitor exceedance (now defined as deviations)	Yes; however, note that the title of the report is the compliance report; deviations include excess emissions and parameter exceedances.
§63.10(e)(3)(iv)–(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions or parameter monitoring exceedance (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§63.8(c)(7)–(8) and 63.10(c)(5)–(13)	Yes.
§63.10(e)(3)(vi)–(viii)	Excess Emissions Report and Summary Report	Requirements for reporting excess emissions for CMS (now called deviations); requires all of the information in §§63.10(c)(5)–(13) and 63.8(c)(7)–(8)	Yes.
§63.10(e)(4)	Reporting COMS Data	Must submit COMS data with performance test data	No.
§63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.
§63.11(b)	Flares	Requirements for flares	Yes; §63.987 requirements apply, and the section references §63.11(b).
§63.12	Delegation	State authority to enforce standards	Yes.

Citation	Subject	Brief description	Applies to subpart EEEE
§63.13	Addresses	Addresses where reports, notifications, and requests are sent	Yes.
§63.14	Incorporation by Reference	Test methods incorporated by reference	Yes.
§63.15	Availability of Information	Public and confidential information	Yes.

Subpart GGGa—Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006

E.25.1 General Provisions Relating to NSPS Subpart GGGa [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR Part 60.1(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, for each compressor, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service, except when otherwise specified in 40 CFR Part 60, Subpart GGGa.

E.25.2 NSPS Requirements for Subpart GGGa [40 CFR Part 60, Subpart GGGa]

Pursuant to 40 CFR 60.590a, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart GGGa, for the emission units listed in Condition E.25.1, as specified below:

§ 60.590a Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in petroleum refineries.

(2) A compressor is an affected facility.

(3) The group of all the equipment (defined in §60.591a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, is subject to the requirements of this subpart.

(c) Addition or replacement of equipment (defined in §60.591a) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d) Facilities subject to subpart VV, subpart VVa, subpart GGG, or subpart KKK of this part are excluded from this subpart.

§ 60.591a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act, in subpart A of part 60, or in subpart VVa of this part, and the following terms shall have the specific meanings given them.

***Alaskan North Slope* means the approximately 69,000 square mile area extending from the Brooks Range to the Arctic Ocean.**

***Asphalt* (also known as Bitumen) is a black or dark brown solid or semi-solid thermo-plastic material possessing waterproofing and adhesive properties. It is a complex combination of higher molecular weight organic compounds containing a relatively high proportion of hydrocarbons having carbon numbers greater than C25 with a high carbon to hydrogen ratio. It is essentially non-volatile at ambient temperatures with closed cup flash point of 445 °F (230 °C) or greater.**

Equipment **means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment.**

In hydrogen service **means that a compressor contains a process fluid that meets the conditions specified in §60.593a(b).**

In light liquid service **means that the piece of equipment contains a liquid that meets the conditions specified in §60.593a(c).**

Petroleum **means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.**

Petroleum refinery **means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.**

Process unit **means the components assembled and connected by pipes or ducts to process raw materials and to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482–1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.**

§ 60.592a Standards.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §§60.482–1a to 60.482–10a as soon as practicable, but no later than 180 days after initial startup.

(b) For a given process unit, an owner or operator may elect to comply with the requirements of paragraphs (b)(1), (2), or (3) of this section as an alternative to the requirements in §60.482–7a.

(1) Comply with §60.483–1a.

(2) Comply with §60.483–2a.

(3) Comply with the Phase III provisions in §63.168, except an owner or operator may elect to follow the provisions in §60.482–7a(f) instead of §63.168 for any valve that is designated as being leakless.

(c) An owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of §60.484a.

(d) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §60.485a except as provided in §60.593a.

(e) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §§60.486a and 60.487a.

§ 60.593a Exceptions.

(a) Each owner or operator subject to the provisions of this subpart may comply with the following exceptions to the provisions of subpart VVa of this part.

(b)(1) Compressors in hydrogen service are exempt from the requirements of §60.592a if an owner or operator demonstrates that a compressor is in hydrogen service.

(2) Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E260–73, 91, or 96, E168–67, 77, or 92, or E169–63, 77, or 93 (incorporated by reference as specified in §60.17) shall be used.

(3)(i) An owner or operator may use engineering judgment rather than procedures in paragraph (b)(2) of this section to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in paragraph (b)(2) of this section shall be used to resolve the disagreement.

(ii) If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in paragraph (b)(2).

(c) Any existing reciprocating compressor that becomes an affected facility under provisions of §60.14 or §60.15 is exempt from §60.482–3a(a), (b), (c), (d), (e), and (h) provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of §60.482–3a(a), (b), (c), (d), (e), and (h).

(d) An owner or operator may use the following provision in addition to §60.485a(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86–78, 82, 90, 93, 95, or 96 (incorporated by reference as specified in §60.17).

(e) Pumps in light liquid service and valves in gas/vapor and light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the requirements of §§60.482–2a and 60.482–7a.

(f) Open-ended valves or lines containing asphalt as defined in §60.591a are exempt from the requirements of §60.482–6a(a) through (c).

(g) Connectors in gas/vapor or light liquid service are exempt from the requirements in §60.482–11a, provided the owner or operator complies with §60.482–8a for all connectors, not just those in heavy liquid service.

Subpart VVa—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

E.26.1 General Provisions Relating to NSPS Subpart VVa [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR Part 60.1(a), the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, for each compressor, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service, except when otherwise specified in 40 CFR Part 60, Subpart VVa.

E.26.2 NSPS Requirements for Subpart VVa [40 CFR Part 60, Subpart VVa]

Pursuant to 40 CFR 60.480a, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart VVa, for the emission units listed in Condition E.26.1, as specified below:

§ 60.480a Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in §60.481a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in §60.486a(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in §60.489 is exempt from §§60.482–1a through 60.482–11a.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§60.482–1a through 60.482–11a.

(4) Any affected facility that produces beverage alcohol is exempt from §§60.482–1a through 60.482–11a.

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§60.482–1a through 60.482–11a.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§60.482–1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of §§60.485a(d), (e),

and (f), and 60.486a(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(ii) *Part 60, subpart A*. Owners or operators who choose to comply with 40 CFR part 65, subpart F must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(1)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 65, subpart F, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart F, must comply with 40 CFR part 65, subpart A.

(2) *Part 63, subpart H*. (i) Owners or operators may choose to comply with the provisions of 40 CFR part 63, subpart H, to satisfy the requirements of §§60.482–1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 63, subpart H, the requirements of §60.485a(d), (e), and (f), and §60.486a(i) and (j) still apply.

(ii) *Part 60, subpart A*. Owners or operators who choose to comply with 40 CFR part 63, subpart H must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 63, subpart H, except that provisions required to be met prior to implementing 40 CFR part 63 still apply. Owners and operators who choose to comply with 40 CFR part 63, subpart H, must comply with 40 CFR part 63, subpart A.

§ 60.481a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA) or in subpart A of part 60, and the following terms shall have the specific meanings given them.

***Capital expenditure* means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:**

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$$A = Y \times (B \div 100);$$

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2006 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

Table for Determining Applicable Value for B

Subpart applicable to facility	Value of B to be used in equation
VVa	12.5
GGGa	7.0

Closed-loop system **means an enclosed system that returns process fluid to the process.**

Closed-purge system **means a system or combination of systems and portable containers to capture purged liquids. Containers for purged liquids must be covered or closed when not being filled or emptied.**

Closed vent system **means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.**

Connector **means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.**

Control device **means an enclosed combustion device, vapor recovery system, or flare.**

Distance piece **means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.**

Double block and bleed system **means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.**

Duct work **means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.**

Equipment **means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.**

First attempt at repair **means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices.**

Fuel gas **means gases that are combusted to derive useful work or heat.**

Fuel gas system **means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.**

Hard-piping **means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, P.O. Box 2300, Fairfield, NJ 07007–2300).**

In gas/vapor service **means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.**

In heavy liquid service **means that the piece of equipment is not in gas/vapor service or in light liquid service.**

In light liquid service **means that the piece of equipment contains a liquid that meets the conditions specified in §60.485a(e).**

In-situ sampling systems **means nonextractive samplers or in-line samplers.**

In vacuum service **means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.**

In VOC service **means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of §60.485a(d) specify how to determine that a piece of equipment is not in VOC service.)**

Initial calibration value **means the concentration measured during the initial calibration at the beginning of each day required in §60.485a(b)(1), or the most recent calibration if the instrument is recalibrated during the day (i.e., the calibration is adjusted) after a calibration drift assessment.**

Liquids dripping **means any visible leakage from the seal including spraying, misting, clouding, and ice formation.**

Open-ended valve or line **means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.**

Pressure release means **the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.**

Process improvement **means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.**

Process unit **means the components assembled and connected by pipes or ducts to process raw materials and to produce, as intermediate or final products, one or more of the chemicals listed in §60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482–1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.**

Process unit shutdown **means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:**

(1) An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours.

(2) An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

Quarter **means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.**

Repaired **means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§60.482–2a(b)(2)(ii) and (d)(6)(ii) and (d)(6)(iii), 60.482–3a(f), and 60.482–10a(f)(1)(ii), is re-monitored as specified in §60.485a(b) to verify that emissions from the equipment are below the applicable leak definition.**

Replacement cost **means the capital needed to purchase all the depreciable components in a facility.**

Sampling connection system **means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take nonroutine grab samples is not considered a sampling connection system.**

Sensor **means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.**

Storage vessel **means a tank or other vessel that is used to store organic liquids that are used in the process as raw material feedstocks, produced as intermediates or final products, or generated as wastes. Storage vessel does not include vessels permanently attached to motor vehicles, such as trucks, railcars, barges or ships.**

Synthetic organic chemicals manufacturing industry **means the industry that produces, as intermediates or final products, one or more of the chemicals listed in §60.489.**

Transfer rack **means the collection of loading arms and loading hoses, at a single loading rack, that are used to fill tank trucks and/or railcars with organic liquids.**

Volatile organic compounds **or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in §60.2 Definitions.**

§ 60.482-1a Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§60.482–1a through 60.482–10a or §60.480a(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§60.482–1a to 60.482–10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485a.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§60.482–2a, 60.482–3a, 60.482–5a, 60.482–6a, 60.482–7a, 60.482–8a, and 60.482–10a as provided in §60.484a.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§60.482–2a, 60.482–3a, 60.482–5a, 60.482–6a, 60.482–7a, 60.482–8a, or 60.482–10a, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§60.482–2a through 60.482–10a if it is identified as required in §60.486a(e)(5).

(e) Equipment that an owner or operator designates as being in VOC service less than 300 hr/yr is excluded from the requirements of §§60.482–2a through 60.482–11a if it is identified as required in §60.486a(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.

(2) The equipment is in VOC service only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.

(f)(1) If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the following table instead of monitoring as specified in §§60.482–2a, 60.482–7a, and 60.483.2a:

Operating time (percent of hours during year)	Equivalent monitoring frequency time in use		
	Monthly	Quarterly	Semiannually
0 to <25	Quarterly	Annually	Annually.
25 to <50	Quarterly	Semiannually	Annually.
50 to <75	Bimonthly	Three quarters	Semiannually.
75 to 100	Monthly	Quarterly	Semiannually.

(2) Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in paragraph (f)(1) of this section, provided the operating time of all such process units is considered.

(3) The monitoring frequencies specified in paragraph (f)(1) of this section are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator may monitor at any time during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in paragraphs (f)(3)(i) through (iv) of this section.

(i) When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.

(ii) When monitoring is conducted semiannually (*i.e.* , once every 2 quarters), monitoring events must be separated by at least 60 calendar days.

(iii) When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.

(iv) When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.

(g) If the storage vessel is shared with multiple process units, the process unit with the greatest annual amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to this subpart, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to this subpart of this part, the storage vessel is assigned to any process unit subject to subpart VV of this part. If the predominant use of the storage vessel varies from year to year, then the owner or operator must estimate the predominant use initially and reassess every 3 years. The owner or operator must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

§ 60.482-2a Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485a(b), except as provided in §60.482–1a(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in §60.482–1a(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in §60.482–1a(f).

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in §60.485a(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482–10a; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in §60.485a(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in §60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in §60.485a(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a

control device that complies with the requirements of §60.482–10a, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

§ 60.482-3a Standards: Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in §60.482–1a(c) and paragraphs (h), (i), and (j) of this section.

(b) Each compressor seal system as required in paragraph (a) of this section shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482–10a; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) of this section shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2) of this section, a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of §60.482–10a, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in §60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a) through (h) of this section if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in §60.485a(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of §60.14 or §60.15 is exempt from paragraphs (a) through (e) and (h) of this section, provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

§ 60.482-4a Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in §60.485a(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in §60.482–9a.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in §60.485a(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the

pressure relief device to a control device as described in §60.482–10a is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in §60.482–9a.

§ 60.482-5a Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in §60.482–1a(c) and paragraph (c) of this section.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section.

(1) Gases displaced during filling of the sample container are not required to be collected or captured.

(2) Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.

(3) Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.

(4) Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph (b)(4)(i), (ii), (iii), or (iv) of this section.

(i) Return the purged process fluid directly to the process line.

(ii) Collect and recycle the purged process fluid to a process.

(iii) Capture and transport all the purged process fluid to a control device that complies with the requirements of §60.482–10a.

(iv) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(A) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(B) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;

(C) A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;

(D) A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343 through 40 CFR 61.347; or

(E) A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

(c) In-situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

§ 60.482-6a Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482–1a(c) and paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b), and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

§ 60.482-7a Standards: Valves in gas/vapor service and in light liquid service.

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in §60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, §60.482–1a(c) and (f), and §§60.483–1a and 60.483–2a.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or

(ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, §60.482–1a(c), and §§60.483–1a and 60.483–2a.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with §60.483–1a or §60.483–2a, count the new valve as leaking when calculating the percentage of valves leaking as described in §60.483–2a(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in §60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485a(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in §60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either:

(i) Becomes an affected facility through §60.14 or §60.15 and was constructed on or before January 5, 1981; or

(ii) Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

§ 60.482-8a Standards: Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485a(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §§60.482–2a(c)(2) and 60.482–7a(e).

§ 60.482-9a Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482–10a.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

§ 60.482-10a Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or

greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

(i) Conduct an initial inspection according to the procedures in §60.485a(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in §60.485a(b); and

(ii) Conduct annual inspections according to the procedures in §60.485a(b).

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in §60.486a(c).

(4) For each inspection conducted in accordance with §60.485a(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

§ 60.482-11a Standards: Connectors in gas/vapor service and in light liquid service.

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in §60.482–1a(c), §60.482–10a, or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in §60.485a(b) and, as applicable, §60.485a(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the

monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$$\%C_L = C_L / C_t * 100$$

Where:

$\%C_L$= Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L= Number of connectors measured at 500 ppm or greater, by the method specified in §60.485a(b).

C_t= Total number of monitored connectors in the process unit or affected facility.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors* . (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

§ 60.483-1a Alternative standards for valves—allowable percentage of valves leaking.

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in §60.487a(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with §60.482–7a(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in §60.485a(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in §60.485a(h).

§ 60.483-2a Alternative standards for valves—skip period leak detection and repair.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in §60.487(d)a.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in §60.482–7a.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in §60.482–7a but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in §60.485a(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with §60.482–7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

§ 60.484a Equivalence of means of emission limitation.

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that

achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

(2) The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4) of this section.

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in theFederal Registerand provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in theFederal Register.

(3) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e) of this section.

§ 60.485a Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the standards in §§60.482–1a through 60.482–11a, 60.483a, and 60.484a as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A–7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last

calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in §§60.482–2a(e), 60.482–3a(i), 60.482–4a, 60.482–7a(f), and 60.482–10a(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 of appendix A–7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260–73, 91, or 96, E168–67, 77, or 92, E169–63, 77, or 93 (incorporated by reference—see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 of appendix A–7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

V_{max}= Maximum permitted velocity, m/sec (ft/sec).

H_T= Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1= 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2= 0.7084 m^4 /(MJ-sec) (metric units) = 0.087 ft^4 /(Btu-sec) (English units).

(4) The net heating value (HT) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i= Concentration of sample component "i," ppm

H_i= net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole.

(5) Method 18 of appendix A–6 of this part or ASTM D6420–99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420–99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504–67, 77, or 88 (Reapproved 1993) (incorporated by reference-see §60.17) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382–76 or 88 or D4809–95 (incorporated by reference-see §60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D of appendix A–7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with §60.483–1a or §60.483–2a as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L / V_T) * 100$$

Where:

$\%V_L$= Percent leaking valves.

V_L= Number of valves found leaking.

V_T= The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with §60.482–7a(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

§ 60.486a Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(3) The owner or operator shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(b) When each leak is detected as specified in §§60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482–7a(c) and no leak has been detected during those 2 months.

(3) The identification on a connector may be removed after it has been monitored as specified in §60.482–11a(b)(3)(iv) and no leak has been detected during that monitoring.

(4) The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) Maximum instrument reading measured by Method 21 of appendix A–7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in §60.482–10a shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in §60.482–10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§60.482–2a, 60.482–3a, 60.482–4a, and 60.482–5a are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482–2a, 60.482–3a, 60.482–4a, and 60.482–5a.

(e) The following information pertaining to all equipment subject to the requirements in §§60.482–1a to 60.482–11a shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482–2a(e), 60.482–3a(i), and 60.482–7a(f).

(ii) The designation of equipment as subject to the requirements of §60.482–2a(e), §60.482–3a(i), or §60.482–7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

(3) A list of equipment identification numbers for pressure relief devices required to comply with §60.482–4a.

(4)(i) The dates of each compliance test as required in §§60.482–2a(e), 60.482–3a(i), 60.482–4a, and 60.482–7a(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with §60.482–1a(e), a

description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

(7) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

(8) Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A–7 of this part and §60.485a(b).

(i) Date of calibration and initials of operator performing the calibration.

(ii) Calibration gas cylinder identification, certification date, and certified concentration.

(iii) Instrument scale(s) used.

(iv) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A–7 of this part.

(v) Results of each calibration drift assessment required by §60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(vi) If an owner or operator makes their own calibration gas, a description of the procedure used.

(9) The connector monitoring schedule for each process unit as specified in §60.482–11a(b)(3)(v).

(10) Records of each release from a pressure relief device subject to §60.482–4a.

(f) The following information pertaining to all valves subject to the requirements of §60.482–7a(g) and (h), all pumps subject to the requirements of §60.482–2a(g), and all connectors subject to the requirements of §60.482–11a(e) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with §60.483–2a:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§60.482–2a(d)(5) and 60.482–3a(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480a(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of §60.7(b) and (d) do not apply to affected facilities subject to this subpart.

§ 60.487a Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of §60.482–7a, excluding those valves designated for no detectable emissions under the provisions of §60.482–7a(f).

(3) Number of pumps subject to the requirements of §60.482–2a, excluding those pumps designated for no detectable emissions under the provisions of §60.482–2a(e) and those pumps complying with §60.482–2a(f).

(4) Number of compressors subject to the requirements of §60.482–3a, excluding those compressors designated for no detectable emissions under the provisions of §60.482–3a(i) and those compressors complying with §60.482–3a(h).

(5) Number of connectors subject to the requirements of §60.482–11a.

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486a:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in §60.482–7a(b) or §60.483–2a,

(ii) Number of valves for which leaks were not repaired as required in §60.482–7a(d)(1),

(iii) Number of pumps for which leaks were detected as described in §60.482–2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(iv) Number of pumps for which leaks were not repaired as required in §60.482–2a(c)(1) and (d)(6),

(v) Number of compressors for which leaks were detected as described in §60.482–3a(f),

(vi) Number of compressors for which leaks were not repaired as required in §60.482–3a(g)(1),

(vii) Number of connectors for which leaks were detected as described in §60.482–11a(b)

(viii) Number of connectors for which leaks were not repaired as required in §60.482–11a(d), and

(xi) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§60.483–1a or 60.483–2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

§ 60.488a Reconstruction.

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital costs that would be required to construct a comparable new facility" under §60.15: Pump seals, nuts and bolts, rupture disks, and packings.

(b) Under §60.15, the "fixed capital cost of new components" includes the fixed capital cost of all depreciable components (except components specified in §60.488a(a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the "Applicability and designation of affected facility" section of the appropriate subpart.) For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.489a List of chemicals produced by affected facilities.

Process units that produce, as intermediates or final products, chemicals listed in §60.489 are covered under this subpart. The applicability date for process units producing one or more of these chemicals is November 8, 2006.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: Firing Rate (after startup of Coker #2) 10^3 mmBTU per 12 consecutive month period

Fuel Usage Limits: Existing Heaters

Facility	Limit	Facility	Limit	Facility	Limit
H-200	1601.33	F-1	259.3	F-8A	1246.55
H-300	630.72	F-2	1488.32	F-8B	1246.55
H-1X	1523.36	F-3	1576.8	F-801A	215.5
H-2	282.95	F-4	847.97	F-801B	215.5
H-3	430.99	F-5	427.49	F-801C	215.5
F-200A	1264.94	F-6	190.09	F-101A	208.5
F-200B	1264.94	F-7	317.11	F-102A	208.5
WB-301	620.21	WB-302	488.81	F-401	201.5
ISOM H-1	1342.03	B-501	2809.33		

QUARTER: _____ **YEAR:** _____ **Heater** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: Firing Rate 10^3 mmBTU per 12 consecutive month period

Fuel Usage Limits: New Units

Facility	Limit	Facility	Limit
H-201	1822.1	HU-2 RFG	2014.8
H-202	1822.1	HU-2 Total Gas	8059.2
H-203	1822.1	F-901A	411.7
H-101A	3109.8	F-901B	411.7
H-101B	3109.8	COT1 and COT2 combined	1261.4
H-102	2899.6		
B-601a	367.04		
HU-1 RFG	2014.8		
HU-1 Total Gas	8059.2		

QUARTER: _____ **YEAR:** _____ **Heater** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: Coke Storage & Handling

Facility	Limit
New Coker (#2 Coker) (after permanent shutdown of No. 11B Coker)---	2,190,000 tons per 12 consecutive month period

QUARTER: _____ **YEAR:** _____ **Coker** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: Gasoline Loaded, after installation of VRU/VCU
Facility: Marine Loading Dock
Limit: 4,000,000 barrels per 12 consecutive month period

QUARTER: _____ **YEAR:** _____ **Fuel** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period) After startup of Coker #2
H-200	8.9
H-300	3.5
H-1X	8.4
H-2	1.6
H-3	2.4

QUARTER: _____ **YEAR:** _____ **Coker** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit
ISOM H-1	7.4 tons per 12 month period after startup of Coker #2

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period)
F-200A	7.0 (after startup of Coker #2)
F-200B	7.0 (after startup of Coker #2

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit
F-401	1.1 tons per 12 month period after startup of Coker #2

QUARTER: _____ **YEAR:** _____ **Coker** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: Annual Firing Rate

Facility	Limit (per 12 consecutive month period)
New Boiler 1 and 2 combined	9,907,560 mmBTU

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: NOx, SO2 and CO emissions

Facility	Limit (tons per 12 consecutive month period)
New Boiler 1 and 2	NOx = 322.0 (combined total) SO2 = 24.9 (each) CO = 118.9 (combined total)

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION
Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period) After startup of Coker #2
F-1	1.4
F-8A	6.9
F-8B	6.9
F-2	8.2
F-3	8.7
F-4	4.7
F-5	2.4
F-6	1.1
F-7	1.8

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

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OFFICE OF AIR QUALITY
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Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period) After startup of Coker #2
B-501	15.5

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
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Month 1			
Month 2			
Month 3			

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Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions (tons per 12 consecutive month period)

Facility	Limit
H-201	10.1
H-202	10.1
H-203	10.1
H-101A	17.2
H-101B	17.2
H-102	16.0
F-901A	2.3
F-901B	2.3

QUARTER: _____ **YEAR:** _____

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Month 1			
Month 2			
Month 3			

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Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period)
F-801A	1.2 (after startup of Coker #2)
F-801B	1.2 (after startup of Coker #2)
F-801C	1.2 (after startup of Coker #2

QUARTER: _____ **YEAR:** _____

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Month 1			
Month 2			
Month 3			

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Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period)
F-101	1.2 (after startup of Coker #2)
F-102A	1.2 (after startup of Coker #2)

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: SO2 emissions

Facility	Limit (tons per 12 consecutive month period)
WB-301	3.4 (after startup of Coker #2)
WB-302	2.7 (after startup of Coker #2)

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: NOx, SO2, and CO emissions
Facility: FCU 500

Pollutant	Limit (tons per 12 month period) After startup of Coker #2
NOx	155.3
SO2	200.3
CO	147.2

QUARTER: _____ **YEAR:** _____ **Coker** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: FCU 500
Parameter: Fresh Feed – barrels per 12 consecutive month period

After startup of Coker #2: 37.6 million barrels

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

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Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: FCU 500
Parameter: Coke burned per 12 consecutive month period

After startup of Coker #2: 669,191,000 pounds

QUARTER: _____ **YEAR:** _____ **Coker** _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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Deviation has been reported on: _____

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Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Parameter: NOx, SO2, and CO emissions
Facility: FCU 600

Pollutant	Limit (tons per 12 month period) After startup of Coker #2
NOx	49.7
SO2	190.0
CO	92.1

QUARTER: _____ **YEAR:** _____ **Coker** _____

Month	Column 1	Column 2	Column 1 + Column 2
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Month 1			
Month 2			
Month 3			

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Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: FCU 600
Parameter: Fresh Feed – barrels per 12 consecutive month period

After startup of Coker #2: 24.09 million

QUARTER: _____ **YEAR:** _____

Month	Column 1	Column 2	Column 1 + Column 2
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Month 1			
Month 2			
Month 3			

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Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: FCU 600
Parameter: Coke burned per 12 consecutive month period

After startup of Coker #2: 428,802,000 pounds

QUARTER: _____ **YEAR:** _____ **Coker** _____

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Month 1			
Month 2			
Month 3			

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Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: GOHT and South flares
Parameter: Fuel burned (10^3 cubic feet per 12 consecutive month period)

	Pilot Gas	Purge Gas
GOHT Flare	3,679.2	24,703.2
South Flare	3,679.2	28,908.0

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Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: HU Flare
Parameter: Fuel burned (10^3 cubic feet per 12 consecutive month period)

Pilot Gas

HU Flare 2,233.80

QUARTER: _____ **YEAR:** _____

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Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Mailing Address: P.O. Box 710, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-6741-00453
Facility: Coke Handling
Parameter: Alternative Operating Scenario

Hours of operation 438 hours in 12 consecutive month period

QUARTER: _____ **YEAR:** _____

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